ELECTRICITY COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:)
)
JULY 2006 CALIFORNIA HEAT STORM)
_________________________________)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, AUGUST 29, 2006

9:05 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMITTEE MEMBERS

Jeffrey D. Byron, Presiding Member

John Geesman, Associate Member

CEC COMMISSIONERS and ADVISORS PRESENT

Jackalyne Pfannenstiel

Arthur Rosenfeld

Kevin Kennedy

Melissa Jones

CPUC STAFF PRESENT

Stephen St. Marie
Senior Advisor to Commissioner Bohn

Sean Gallagher

CEC STAFF PRESENT

Tom Gorin

Scott Matthews

PANELISTS

Michael Gibbs, Moderator
ICF International

Richard Aslin
Les Guliasi
Byron Marler
Pacific Gas and Electric Company

Bob Emmert
California Independent System Operator

Mike Cockayne
Los Angeles Department of Water and Power

PANELISTS

Art Canning
Southern California Edison Company

Daniel R. Canyan
Scripps Institution of Oceanography

Greg Katsapis
Tim Vonder
San Diego Gas and Electric

Jim Detmers
California Independent System Operator

Birgit Koehler
Bonneville Power Administration

Steven Kelly
Independent Energy Producers Association

Randy Howard
Los Angeles Department of Water and Power

Kevin Dasso
Pacific Gas and Electric Company

Gary Schoonyan
Southern California Edison Company

Robb Anderson
San Diego Gas and Electric

Junona Jonas
Santa Clara Silicon Valley Power

Loren Lutzenhiser
Portland State University

Wally McGuire
FlexYourPower

Andy Green
County of Contra Costa

Jane Turnbull
California League of Women Voters

Ken Kremesec
El Dorado Irrigation District

PANELISTS

Lon House
Association of California Water Agencies

Bob Kinert
Pacific Gas and Electric Company

Earl Bouse
factor (n) associates for
Hanson Permanente Cement

ALSO PRESENT

Bob Kinert
Pacific Gas and Electric Company

William Marcus
JBS Energy
representing The Utility Reform Network

Gary Ackerman
Western Power Trading Forum

INDEX

I N D E X

I N D E X

P R O C E E D I N G S

9:05 a.m.

MR. GIBBS: Thank you, Sylvia. Welcome, all. Welcome, Commissioners, to the workshop on the California heat storm July 2006.

Our format today is four panels, each discussing an important aspect of the heat storm, including what it was, how it affected the power system, how customers reacted and what lessons we may take going forward.

We're fortunate to have on our panels a distinguished group of experts including utility representatives, forecasters, researchers who have examined the relationship between weather and load, and representatives of some key customers.

Following the panels in the afternoon we will have an open floor for comment from those who are in attendance here, as well as those who are on the phone, to provide their perspectives and input.

So, to get started I'd like to turn to the Commissioners for their opening remarks.

PRESIDING MEMBER BYRON: Thanks, Michael. Hi, my name's Jeff Byron. I do have some remarks I want to start with. Thank you, Michael.

You know, I remember during the energy crisis in 2000 I was working as the Energy Director at a large software company and we were hosting our first energy summit. Some of you here were there, I believe. And we were told by a number of folks that there was a 5 percent chance that we'd be having rolling blackouts. You may recall that was an, as yet, unheard of concept in 2000.

And the consensus of many of the policymakers at the event was that this was not a sufficiently high enough probability for customers to be concerned. And as we all know, 5 percent ended up being a high enough probability to be concerned.

But even before the blackouts began, the far bigger issue for many large customers was the financial impact of their power interruptions. We had to prepare for blackouts and develop mitigation strategies. Many companies have implemented permanent strategies since then, but just as many, perhaps a lot more, are still susceptible to the economic impact of rolling blackouts.

The middle of this past July saw the beginning of a heat storm the likes of which we've not seen for decades. And it significantly taxed the electric power system in California and throughout the west. There were no rolling blackouts. Perhaps there was a bit of luck involved, but the outcome was not by accident.

There are a number of organizations, companies and individuals that deserve a great deal of credit for keeping the electricity flowing during that period. That's not to say that everything went perfectly, but in general, those that kept the lights on deserve recognition and our thanks.

Some of those people are with us today. We'd like to thank the ISO, the generators, the utilities and the operators who did an extraordinary job preparing and executing during the heat storm.

And this brings me to the reason why we are conducting this workshop today. During an energy crisis or a challenging event, such as the heat storm, there's always something we can learn from the experience. The purpose of this workshop is to see what lessons we've learned and what actions we might take so that we can work to avoid or deal better with a similar event in the future.

First, I'd like to thank everyone who agreed to be here today on such short notice and to provide their observations, insights and findings. We have a number of experts here to discuss weather, the nature of the electric load, and the operation of the grid.

We have experts on the supply side of the equation who operate the grid and provide electricity to their customers. And we have experts on the demand side, sometimes referred to as customers.

I'd like to again thank you all for being here. I'm reminded of that old line, everyone keeps talking about the weather, but nobody seems to be doing anything about it. That may be true, but we can always do a better job of preparing for it and responding to it. That's what we want to address here today.

This is not an evidentiary hearing. We are not here to find fault. We want this to be a constructive and collaborative effort. And we want to build upon a job well done and to better prepare for the next time this may happen.

So, we've compiled an excellent set of panelists. I thank the staff very much for that. We have Michael Gibbs here as our moderator, to provide the kind of open forum, and to facilitate learning and discussion. He'll also help keep us on time, I hope.

I believe he indicates there's four panels. The first three will help us to understand what happened during the heat storm; how the system responded and what the impact was on customers. The last panel is comprised of representatives from the ISO, CPUC and CEC who will pull together what we've learned, and perhaps draw some conclusions and actions that we can take.

Of course, we'll also provide time at the end of public comment. And I believe there's a sign-up sheet for that. I don't think we're too formal here today, any and everyone will have opportunity to speak.

But before I turn it back over to Michael, of course I'd like to make sure you know who all is up here, and make sure there's a chance for any others to speak.

Commissioner Geesman, would you like to

add anything?

ASSOCIATE MEMBER GEESMAN: No, thank you.

PRESIDING MEMBER BYRON: And we have other members of the Energy Commission, Chairman Pfannenstiel.

CHAIRPERSON PFANNENSTIEL: Nothing, thank you.

PRESIDING MEMBER BYRON: Commissioner Rosenfeld?

COMMISSIONER ROSENFELD: Nothing, thank you.

PRESIDING MEMBER BYRON: And representing the PUC we have Commissioner Bohn's Senior Advisor, Stephen St. Marie.

MR. ST. MARIE: Thank you very much. Nothing.

PRESIDING MEMBER BYRON: Okay. Melissa, would you like to -- all right, well, I'm sorry I took all that time up, then. Please, Michael, take us away.

MR. GIBBS: Okay, thank you very much. The way we're going to start our first three panels is to have an overview presentation. Tom Gorin is going to start us off on panel number 1.

While he is making his way over to the podium, if the other members of panel number 1 could join us at the table here, we'd appreciate that. And grab a nametag. You can sit anywhere to respond.

And after Tom gives his presentation I will ask you each to introduce yourself. While you're getting situated -- Tom, if you would introduce yourself, and then we can begin. Thank you.

MR. GORIN: I'm Tom Gorin from the Demand Analysis Office of the Energy Commission. I work on the statewide forecast.

I'm going to try and make this quick. This is just sort of an overview to stimulate discussion for each of the other panelists.

As you can see from this map, July 24th was hot all over the country. This is a graph of the load on the top and the temperatures for PG&E, SCE, San Diego and the red temperature for the ISO. You can see starting on that Monday, the 17th, it was hot in PG&E and the loads were relatively high and it was more than Edison.

Probably the major heat buildup was on Saturday. You can look at the difference in temperature in San Diego between Friday and

Saturday is probably a large reason why San Diego peaked on Saturday from its load perspective.

The southern California temperatures peak on Saturday, whereas PG&E peaked on Sunday. Cumulatively that brought us to Monday, where I think by that time everybody knew it was going to be hot. We were in for trying to figure out how high the loads were going to be.

This is a busy graph, but it's the temperatures from June 15th through the summer. And for all three utilities, from June 15th through actually the 27th of July, the temperatures have been relatively above normal. PG&E went below normal a couple of times; the dotted lines are 56-year average temperatures.

One thing that hadn't happened previously this summer that happened around the 22nd to the 24th was there was a coincidence in all three service areas of high temperatures. In June, when it got hot, it got hot in PG&E, and then a few days later it got hot in Edison. There was coincidence here in early July, but San Diego showed it cool.

And the remainder of the chart is the rest of the summer, while we're talking about record temperatures in July, August has been relatively benign.

This is a weighted temperature of the ISO which shows essentially the same pattern. This only goes through the end of July. And peak temperatures for the ISO service region were above three standard deviations above normal, calculated using the last 56 years worth of data, which is something you don't see very often.

In 1998, the last time we had a heat storm we were talking about things that were a little over two standard deviations above normal.

The purpose in these maps is to point out geographical distribution of temperatures. We can talk about the temperature for the nation, the temperature for the region, or temperature for the state. I get called a lot of times, people wanting to know what the temperature is in California -- one temperature.

Temperatures, these are more disaggregated chart, are divisions that are made up at NOAA, and they seem to be rather homogeneous region. You can see here along the south coast July was the hottest July on record for the last 112 years. And this is where population center in

California, all along the coast. And so that was really warm and added to our peak.

This is the disaggregation that load sees, the temperature. This is provided by Laura Edwards at the Western Regional Climatic Center, Desert Research Institute. And it's a project funded by PIER, it's California climate archives. They have western regional maps.

But you can see this week was hot in the valley, hot in the southwest, hot in the northwest. And classified as a general westwide heat event.

This chart I put together right after the heat event. This temperature, this is the ISO weighted statewide temperature for August 24th. These are the number of days since 1950 that have exceeded that temperature. There were four days in 1955 and two days in 1988. 1998 is not on there, the weighted temperatures were slightly below the Monday temperature.

Two things are interesting to note here. This temperature is driven by higher temperatures in PG&E. All these other events are driven by higher temperatures in Southern California Edison. Being that some of them are in September, I would guess that they're driven by Santa Ana conditions which are hot, dry conditions; and don't have the humidity associated with the events that we saw in July.

If you look at the Saturday temperature from the ISO, you eliminate all of these years. And there's two years with temperatures higher than the last 56 years.

These are chronological charts of annual maximum temperatures in the ISO region for the Monday,the 24th. So, from a strictly temperature perspective, we can say that that was a one-in-ten temperature event. That doesn't consider minimum temperatures; it doesn't consider humidity or anything else.

This is a similar temperature for Edison. By Monday the temperature in Edison was lower. Saturday temperature was probably a one-in-seven or -eight event, temperatures event.

The other thing that's interesting to point out that since 1998 temperatures in southern California have been rather benign. And so I think people acclimate to what the temperature's been in the last few years. So all of a sudden now it's hot there. But it has been hot in previous years.

This is PG&E. PG&E had probably, by far, the highest temperature that it's seen in the last 30 years. Also had record low temperatures due to, in part, increased humidity.

So, what does temperature have to do with demand forecast. This is sort of a bibliography of previous work that we've done. The last time we had a heat storm was 1998. So there was a paper published on that in March of last year. We were looking at one-in-ten weather adjustments for the utilities for the supply/demand balance. In June of this year we looked at weather normalizing last summer's peak to upgrade the current forecast. And all of these events, we looked at the relationship of temperature to loads.

In our forecast we have published a one-in-two, one-in-five, one-in-ten and one-in-20 peak forecast. I don't think that these forms were actually looked at very much until it got hot. But, they are available. And I think the resulting loads are not too out of line with what we actually forecast to happen in those temperature events.

We put together a one-in-40-year forecast, but we decided not to publish it. We will probably publish it next time.

ASSOCIATE MEMBER GEESMAN: Tom, I'm unclear here as to on this chart the extent to which it reflects the updated forecast that we made in June.

MR. GORIN: The updated forecast in June refers to the PG&E, SCE and San Diego areas.

ASSOCIATE MEMBER GEESMAN: Everything else was --

MR. GORIN: Everything else is --

ASSOCIATE MEMBER GEESMAN: -- '05.

MR. GORIN: -- from the 2005 IEPR. The reason for the update was for the procurement process for PUC.

ASSOCIATE MEMBER GEESMAN: Well, it was also reflecting the fact that, as I understand it, weather-adjusted demand in 2005 turned out to be about 2000 megawatts more than we had forecast for 2005, wasn't it?

MR. GORIN: Right. This is a graphical representation of those forecasts. For the ISO it turns out that the actual load, plus estimates of demand response and outages is a little bit higher than the one-in-20 forecast.

One thing to notice is that the one-in-20 forecast -- well, the one-in-10 forecast is actually higher than our 2010 one-in-two forecast. I think a lot of the press that's been out in forecasts have indicated that we've surpassed our 2010 forecast. I think most of that is due to the weather being abnormal this year.

And in that light, this is ISO loads determined by the temperature/load relationship that was developed using the 2005 ISO daily peaks and the ISO temperatures. The same methodology that we used in the one-in-ten update, and the revised forecast update.

Those loads, so this would be 2005 ISO load, weather-normalized to each specific year's weather pattern.

You can see the last three years have been below normal. 2006 results in the second -- or that Monday results in the second-highest load that the weather history would calculate. And the difference between 2005 and 2006 results in the 13.8 percent growth which could be attributed to weather.

These are similar charts for each of the service areas. This is for PG&E. Not all of you were here at the June weather update. PG&E, the updated forecast for PG&E was a combination of PG&E's weather adjustment and the staff weather adjustment. So this is an extrapolation of both PG&E's and the staff's weather adjustment methodology.

These open boxes are the one-in-two weather adjustment that we used in June. This is what happens when you put the actual 2006 weather that we saw on that Monday into those equations. The change from 2005 in the staff's work has 2006 based on weather is 11.7 percent.

This is a similar chart for Edison. That results in a change in growth due to weather of 7.8 percent. And similar thing for San Diego at 7.9 percent.

And this is a daily tracking of our forecast which would be the updated forecast for the ISO, using the revised 2006 forecast presented in July -- I mean in June, for this year. And adding 1.55 percent growth for the '05 to '06 growth.

There is some question in June of are we going to come back and see an extra 2000 megawatts this year that we saw last year. I think on the actual peak day we over-forecast peak, and that may be due to interruptibles and demand response.

But in general, up to that point, you can say maybe the forecast was under-forecasting a little bit. Now we're over-forecasting, which may mean that people had seen their bills. But I think from an overall standpoint, the growth that we projected from the revised forecast is in the ballpark of what's happening.

ASSOCIATE MEMBER GEESMAN: When you draw that conclusion do you make any adjustment for customers that were blacked out because of distribution system failures at the time of peak?

MR. GORIN: No. We're still trying to figure out the coincidents for those and the actual number of megawatts that that saved on the peak.

So this is just compared to the ISO projected daily load, the ISO reported daily load.

So that concludes my presentation.

MR. GIBBS: Okay, thanks, Tom. Any other questions from the Commissioners right now? If not, I'd like to -- thanks, Tom, you can find a seat back over here.

I'd like to start over here on this side and have the panelists introduce themselves, and then we'll start a discussion of building off of what Tom had to say.

So, if we can just quickly go around and just introduce yourself, please.

MR. GULIASI: Les Guliasi. If I may beg your indulgence for a moment here, I wanted to provide for the Committee a little bit of some context to the various presentations that PG&E is going to make and the dialogue that we're going to engage in.

What I want you to do is --

MR. GIBBS: If you don't mind, I'd just like to have everyone introduced themselves first, and --

MR. GULIASI: Okay. Okay, fine, thanks.

MR. GIBBS: -- then get into that. Thank you very much.

MR. MARLER: I'm Byron Marler with PG&E.

MR. ASLIN: Rick Aslin with PG&E.

MR. EMMERT: Bob Emmert, California ISO.

MR. CANNING: Art Canning, Southern California Edison.

MR. COCKAYNE: Mike Cockayne, LADWP.

MR. KATSAPIS: Greg Katsapis, SDG&E.

MR. VONDER: Tim Vonder, SDG&E.

MR. CANYAN: Dan Canyan, Scripps Institution of Oceanography.

MR. GIBBS: Great. And, Tom, thank you very much.

MR. GIBBS: Great. And, Tom, thank you very much. Tom put forward, I think, a couple notes, if I could just start us off here, and then we can get into comments. Look forward to everyone's perspective.

What I took away from what Tom has said is that the event was extreme, but not unprecedented. We've seen high temperatures before, and there were high temperatures this time. But they were not completely outside of our range of experience.

And the second thing I took away from his presentation is that the forecasts were not way off. In fact, the forecasts were pretty reasonable.

So, with those observations that I've made, I'd like to hear comments from folks here on the panel, and maybe just starting off we can start over here on my right with PG&E, if you want to say a couple words, and then get some perspectives on PG&E's view of the event.

MR. GULIASI: Thanks very much. Again, what I wanted to do for you, Commissioners, is just to provide some general context so that what you take away from the PG&E presentation is not merely a series or a set of disparate, you know, remarks and comments as part of this dialogue, but instead you see it as kind of an overall whole with some theme.

In addition to hearing from Byron Marler and Rick Aslin about forecasts and weather, you're going to hear from Kevin Dasso later on this morning about the operational event and our response to operational conditions.

But, in addition to that we have with us today, Bob Kinert from our customer services organization, and perhaps at the conclusion of the third panel we can make five or so minutes available to him.

What we wanted to do was tell you what PG&E did in preparation for the unusual weather that we were about to experience. We didn't take this temperature situation, this heat storm, as business as usual. We extended ourselves to our customers.

We worked carefully and closely with our largest customers, asked for voluntary interruption and curtailment of load. We worked extensively with our customers throughout the event to insure that we could restore service as quickly as possible. We moved crews throughout our service territory to the hardest hit areas.

So we wanted to convey to you kind of an overall sense of what we did in preparation for the event, during the event, and some of the lessons learned afterwards.

So with that, I'll turn it over now to my colleagues from PG&E. Thank you.

MR. GIBBS: Great. Thank you very much. And, Byron, your thoughts on Tom's presentation and PG&E's perspective.

MR. MARLER: Okay. Well, I compliment Tom; he's done a very nice job of bringing together the temperature information and load information for the whole state, and then aggregated down to our PG&E area.

I have a presentation that I'm going to make; I don't know when that's going to happen, but I can do that now. I just wanted to say that what Tom has shown on the temperature data, I believe, is maximum temperatures. And one of the things that I've done in my own analysis is to look at the daily average temperature; and see what that meant to us, as well.

So, I'll make my presentation now.

(Pause.)

MR. MARLER: Okay, so it's me, Byron Marler. And the thing I wanted to point out in the title here, and I say July 2006 heat wave/storm, I'm a trained meteorologist, and you can go to all kinds of courses in meteorology and you'll never see the term heat storm in meteorology. But after working for the utility for 32 years, I know that it is a heat storm because it affects our utility just like a wind storm or a winter storm.

So, what I wanted to show is some information about the weather pattern, what's going on. Here you see an upper air pressure pattern, satellite, 5:00 p.m. on July 22nd. And California -- it's right in here, that's about San Francisco and this is about Los Angeles.

And what you're seeing here is a contour of pressure; this is actually in meteorology lingo, high. But if you just think of it as pressure, and this a big high pressure area that's covering the entire western states here, going from, you know, down from San Diego all the way up to Seattle and then across over to western Montana and back down into Colorado, New Mexico, Arizona.

So what this is doing, and you see the white stuff here, that's clouds, what it's doing is it's bringing in warm air from the south, and it's also bringing in some moisture from the south, as well. And what has happened is we have thunderstorms that developed on the Tehachapi Mountains, the southern and central Sierra, the San Gabriel Mountains, so there was enough moisture to trigger thunder storm activity on this day and the following day.

And so I'll just show this next slide. So this is just a little bit later on that day, it's 9:00 p.m. And what you see over California, here's California again, is you see this cloud cover. I called it the debris clouds that come off the thunderstorms that built over the mountains. And they've come up from the south with that flow of southeast, out across the San Joaquin Valley; and they continue to move northward across the Central Valley during that night.

And what cloud cover does is it tends to hold the heat in, like a blanket. So, what happened on that night was the nighttime temperatures between the 22nd to 23rd did not go down very much. For example, Fresno's low temperature the morning of the 23rd, or the night of the 22nd, was 90 degrees. That's the low temperature, okay.

So, anyway, talking a little bit about the temperatures, here's some temperature records for our service area. We have Santa Rosa, San Francisco, San Jose, Ukiah, Red Bluff, all the way over to Bakersfield. Fresno's in here.

And what you're seeing is from the 16th to the 26th of July the daytime high temperatures -- and here's the normal for each site. For example, Santa Rosa, the normal high temperature at Santa Rosa is 82. So what you're seeing now in this column, in each case, is the difference between the normal and the actual. And I just put in some colors, yellow being 12 degrees above normal, and the pink being 18 degrees or more above normal.

So you're seeing places like Santa Rosa here being more than 18, well, actually in this case 26, 25 degrees above normal. San Jose 19, 21 degrees above normal. And on over to, well, let's see, Livermore 23. So anyway, we know, it was hot.

But what is also interesting is the nighttime temperatures. And I was pointing out that cloud cover. And so again, same format. We have the normal lows, like Santa Rosa's normal low is 53; Stockton's normal low is 62. Out here at Stockton on the 22nd, the low that night on the 22nd was 80; the low the next night was 82. So that was 18 and 20 degrees above normal on the low temperatures.

And Fresno, even moreso. Again, the coloration 12 degrees is yellow; 18 degrees above normal is the pink.

Then I did something to the temperatures, themselves, not just the differences, but the minimum temperature 70 or greater, minimum temperature 80 or greater. So what you're seeing here, Red Bluff, 80 is the low. Stockton 80 and 82; Fresno -- now, maybe you're thinking well, that's no so unusual, but again, Fresno, I think, is saying 67 is the low. So, anyway, very warm night. That's the whole point of this slide, very warm night.

And when you put that together with the warm daytime temperatures, then you have a daily average temperature. And that's what this graph is all about. And it's showing top eight heat waves 1949 to 2006 in the PG&E service area.

And what these are, are daily average temperatures. Tom's was presenting maximum temperatures; this is the high and the low divided by 2.

And so what you see here is temperature, and you've got a number of days on this axis. Day 8 is always the highest temperature. And so what happens is we have the July 23rd, the daily average temperature for PG&E's service area, as averaged by Redding, Sacramento, Stockton, Fresno, Santa Rosa, Oakland, Livermore, San Jose, Salinas and Paso Robles, as being the hottest -- well, the eighth day is the hottest day, it's about 91.

And if you look at that curve it's above, it's like head and shoulders above all the other heat waves that we've had here in this collection of heat waves. It was interesting, I actually found this July 14th '72 heat wave at least, on a two-day basis, to be hotter than the '71 case. And I think maybe Tom's analysis, while he's looking at maximum temperatures, and truly, that's part of the difference. He had '71 as being one of the hot ones. And it's in there, it's that yellow curve.

Anyway, bottomline, this was the biggest heat wave we've seen in this period as an average of these locations.

ASSOCIATE MEMBER GEESMAN: You don't seem to include the 1955 incident, which has gotten a fair amount of attention in the press as comparable in terms of deaths. Is there a reason for that?

MR. MARLER: I can't answer that. I mean my data analysis did look at that period, and for some reason it's not showing up. Actually, yes, so I can't answer the question. I will look into it.

Okay, so what I did now, same type of analysis; I just took and subdivided our territory into coastal valleys and central valley. And it's just showing the same thing, that recent heat wave of July 23, 2006, is the hottest one in both coastal valleys and central valley.

Now, coastal valleys is Santa Rosa, Livermore, San Jose and Paso Robles. So it's like one mountain range in from the ocean. Okay, why I'm going to make that point is that this chart shows the number of years since the three-day average. I think, as you can see, that on those previous graphs that we had, three very hot days, the 22nd, 23rd, and 24th.

And so I was looking at the three-day average temperature. And a number of years since those temperatures being hotter than the 23rd to the 25th, three-day average ending on the 23rd, 24th and 25th.

And what these are, you can't read them very well, but this is a 50-year contour, the eastern-most one here. This is a 30-year contour. And then right along the coast is a ten-year contour. And places like San Francisco and Salinas and Monterey and Santa Maria, it was less than a ten-year -- I mean there was actually a heat wave that occurred about two to six years ago, there's a couple of them that were more significant than this.

But as soon as you got in past the first row of coastal mountains, the statistics started changing. And once you're in past the second and third row of those mountains, you're into this greater than 50-year period, with the exception of the Red Bluff/Redding area, and the exception of the Fresno area.

I also did this -- I don't have a graph to show you, but I also did this for the one-day average temperature. And the only, it's almost the same pattern except right in the Bay Area here, the ten-year contour comes into the Delta a little bit. Not over to Stockton, but into places like Vacaville and Fairfield and Pittsburg and Antioch. But almost the same pattern.

So, anyway, my conclusions is that it was warm overnight; warm overnight temperatures occurred on the 22nd to the 24th. Very warm the night of the 22nd, 23rd. Fresno was 90; Stockton 82; Livermore 79; San Jose 74. Hottest 24-hour temperatures in 57 years in many locations on July 23rd. Hottest two-, three- and four-day period, that's running average period, at many locations during that period.

Daily average temperatures in areas show that this was the longest, I shouldn't say strongest -- longest, strongest -- longest hottest heat storm as compared to others. I don't like that word.

Okay, with the exception of immediate coast, like Morro Bay, Monterey, San Francisco, and adjacent to the San Francisco Bay shoreline, like San Rafael and Richmond and Oakland. The remainder of the service territory experienced near-record heat and it was similar but slightly less intense on maximum temperatures to the '72 heat event in the PG&E service area.

So, that's what I had to say on that.

MR. GIBBS: If I could just ask a quick question. I notice you're specifically talking about 57 years; that's the full record of data that you have?

MR. MARLER: That would be from 1949 to 2006. Yes.

ASSOCIATE MEMBER GEESMAN: Did you track humidity in your data?

MR. MARLER: I have some humidity data; and I did -- we don't track it. In our area it's not as significant as elsewhere in, I would say, people's heat comfort level. It is a factor, but not as important as just the temperature.

I did look at the humidity. In fact, I shouldn't say humidity, because humidity is a thing that fluctuates by hour of day up and down. When it's hot the humidity's low; when it's cool the humidity's high.

It's more appropriate to use the dew point temperature as a indication of atmospheric moisture. And I did look at Fresno; I looked at Davis, California during this event.

Prior to the true teeth of the heat wave, the dew points were averaging about 57, 58 degrees. On the hottest days it did go up about 5 degrees; it was between 62 and 63 dew point on the hottest days. And so there was some additional moisture in the air during the teeth of this heat wave.

ASSOCIATE MEMBER GEESMAN: I mean do you have historical dew point temperatures for your weather stations?

MR. MARLER: Well, the weather stations are pretty much, a lot of them are on the National Weather Service sites. And they do have a dew point value in their history. It could be analyzed, yes.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. GIBBS: Great, thanks. Thank you very much. I think Dan has also had a chance to look at weather data, and this would be a good time to make comment on that.

MR. CANYAN: Okay, yeah. If it's okay I'll just show a couple slides.

Well, I thought those were two really good descriptions of elements of this event. And I'm going to try to complement that and probably reinforce what you just heard.

I should acknowledge Sasha Gorshunov; also Laura Edwards from Western Regional Climate Center -- within the Scripps.

Okay, somebody has to tell me how to run this. I think I just got it.

So, what I've got here, I'm not a utilities guy; I'm a climatologist. So I have a slightly different definition; it's probably more liberal than the ones you've heard from Byron and Tom. But the message is pretty much the same.

So, here's a picture of a composite heat storm or heat wave designed from California data, where several stations in California are registering extreme warm daytime temperatures.

And this is the anomalous temperature;

departure from normal for temperatures across the United States. And what you see is that when California is in this state of extreme warmth, indeed the entire west is usually blanketed by warm temperatures, which has a bearing on us, I think, because we share electricity over the western intertie, and things get complicated if everybody's warm.

Byron already mentioned this high pressure which is really the driving circulation mechanism that leads to this. You can see, well, it's warm here in the west, it's cool downstream over the eastern part of the country.

So I just said this, that we designed our own heat wave index, and I'm not going to go into the details now because we don't have enough time. This is simply a seasonal census of heat waves by this particular index. These are heat wave days, and you can see that they rise precipitously, or have risen precipitously in June and continue through September and a little bit into October. This is virtually the same data set that Byron just talked about, that goes back to about the end of World War II forward.

If you look at the evolution of these

circulation patterns which drive these, you can see seeds of the event beginning at least four days before the event happens; and then, of course, the longer heat waves set in and are quite persistent. The atmosphere is not moving very quickly in terms of propagating its wave light features during these events. And that's why they last longer.

Similarly, if you look at the temperature signature you can see the building up. This is a day before the event; this is a day after; this is three days after. At the beginning you can see this very large footprint pattern that's taken hold.

You can see this in various elements of the atmosphere. The air temperatures, of course, this is from the so-called reanalysis data product from the atmospheric community. Forget that going back part.

This is the humidity which actually is kind of interesting in this particular event. And what we've done here, if I can pull this off, is we've looked at this in five-day time slices through the event. This is the period from 8 July through the 12th of July. This is the 13th through the 17th.

And the blue shading here represents higher than normal humidities, okay. You can see California. You can see that at this point in the development, humidities are not exceptional. But you notice that there's some structure down here in the eastern Pacific that now migrates up.

Here's the 18th through the 24th. This is the period that Byron just mentioned when he was showing thunderstorms and convective cloudiness and so forth. And that undoubtedly had a role in the nighttime temperatures that were actually extraordinarily warm during this event.

And then finally here's the tail end of this event; it's still humid. And, well, okay, here's the very tail end, and it's still -- and you can notice that things are starting to happen now over the eastern part of the country. It's interesting that after we experienced our heat wave here in the west, the midwest and then the east, of course, were overtaken. So this episode actually got some attention from the federal government, which is kind of impressive.

Okay, so, the question was asked about actual humidities on the ground. These are dew points during the event. These red dots here possibly can't see the x's, but this is in degrees Celsius here on this temperature scale at the bottom. The blue histogram is actually a climatology of dew points in our heat waves at, in this case, at Fresno.

Okay, so we'd gone back and these are several hot-day events at Fresno, where we just queried the data to determine what are the dew points. Now, I wasn't very discriminate about which days we chose in terms of the 2006 event. So I went all the way back to about the 17th of July. And I went through, I think, about the 26th.

So I have more than just the core days of the event. But you can see that we had a number of days here. This is frequency that's plotted on this chart, so this really represents how many days that we see of dew points that were relatively high. Twenty degrees Celsius is 68 degrees Fahrenheit, just for scale.

So Byron was mentioning that he was seeing dew points in the 60s. And that's this period right here. You can see -- also for contrast, you can see air temperature during the event, compared to other heat wave events. And you can see that there were some remarkably warm days.

The same exercise was done for San Diego. Again, you can see some relatively high dew points in this event. I would say, though, that this is not the only humid heat wave that we've seen on record. There's been others, as you can see from this climatological view. But this one definitely shared that element.

Now, if you look at the -- this is a point that Byron really made well, and I just want to reinforce it. That the maximum -- and Tom -- that the maximum temperatures in this event, 2006, were not exceptional when you compare them historically.

What we're showing here is the number of stations in a statewide network that registered extremely temperatures in view of their own climatology, greater than the 99 percentile temperature had to be recorded at a given station in order for it to register in this series.

So, when you see large excursions here, like in 1971, that was a period where several stations in the state during the summer period were exceptionally warm. And you can see that that did happen in 2006. That's the last line on this chart. But, in terms of the other events that we've seen historically during our lifetimes, this one was not exceptional.

On the other hand, when you look at minimum temperatures, which are shown here on the right, this event was just amazing. It registered in the neighborhood of 50 percent of the stations in this climatological record had their all-time maximums in this particular metric. So this was just a remarkable episode in terms of nighttime temperatures.

The other thing that is of note here, when you look at this statewide minimum nighttime temperature index what you see is how over the last 50 years or so there's been a creeping tendency for minimum temperatures to increase.

Okay, so now how well predicted are heat waves. So what we've done here is we have a record of medium-range forecast model, which is the current generation of the Weather Service's medium-range model; medium range meaning three days to 14, 15 days or so. Okay. So that's the product that at least some of the operational meteorologists would look at, probably along with other modeling products.

But this gives you an idea of how well you could forecast, say, the first day of the heat wave, going back 15 days in advance, 14 days, 13 days, 10 days and so forth. And what you see here, this measure of skill is just the large square, the squared correlation. This happens to be a single station or location sited pretty much over Los Angeles. So it's just a typical location over California.

And what I take from this is that at about seven days in advance we're picking up about half of the variance of the anomalous temperatures so we can see when you have a heat wave, actually a week in advance you get a pretty good precursor that something might be happening.

How well do you do as the heat wave evolves forward; how well forecast the third day of the heat wave, which is important, because multi-day heat waves is, as was pointed out, are really important because humans are involved. And they remember if it was warm the previous day.

And there you can see that we sort of start plateau-ing with this relatively reasonable skill in about seven days in advance. And then by day zero, the first day of the heat wave, all of a sudden you see pretty well that it's going to be a persistent event.

In terms of the fifth day of the heat wave, which, of course, in some events is not a heat wave at all, it could be the demise of the heat wave, how well do we do. Well, we don't do very well at all. It takes until about the second or third day of the heat wave to recognize that the heat wave is either staying or going on the fifth day. So, anyway, that's kind of interesting.

Now, my final little salvo here is the fact that, of course, in some of our careers that what you see, and what we've seen historically, is very likely not what we're going to see in the next few decades.

So, what we have here are some climate change projections and several of us have gone through this exercise. Norm Miller is in the audience, and he has shown these kinds of pictures, too.

This is a typical GCM model forecast that looks at hot days from two different greenhouse gas emission scenarios. Of course, it's uncertain how much humans are going to load the atmosphere in the future.

And there's several scenarios that ar being explored to look at possible consequences to global and regional climates. The Energy Commission, of course, funds their own look at this.

And what is shown on this picture, each dot is a hot day. And the color of the dot represents how hot, okay. How hot above its present-day 99 percentile. And what you see, again, the more conservative, the more restrained greenhouse gas emission scenarios is that, indeed, as you go through time, this is time going up and this is time through the season across here.

So you can see that in the present day, of course, heat waves are usually confined between July and August, and perhaps September. But as time goes on, of course, the width of the heat wave season expands; that is they start coming earlier and they start coming later, too. And their frequency becomes greater; and they intensify during the core of the summer season.

This is really apparent when you look at a greenhouse gas scenario which is less restrained, that is sort of a business-as-usual, or high-carbon diet scenario. You can see the real strong frequency of occurrence of heat waves, particularly at the end of the century.

But what I think I'd like to know is that if you plot the incidence of heat waves as you go through the 21st century, in 20 years or so, if you believe these models, we are seeing two to three times as many heat waves as we've seen historically. So that's not so far out. And that's a period over which a lot of us actually are still making sort of viable plans for the future.

(Laughter.)

MR. CANYAN: So this is something that needs to be taken account of.

Yes, myself included.

That's it, so thanks very much.

MR. GIBBS: Thanks, Dan. Any questions? Well, thank you very much, and highlighting the importance of the minimum nighttime temperature in this past event, I thought perhaps we could maybe ask Mike Cockayne from LADWP to say a few words.

If you have some comments to make from

your chair, there, or if you want to make some --

MR. COCKAYNE: I have some charts, too; I think it's easier to speak from --

MR. GIBBS: Okay, that's right. Yeah, I think you want to speak from some charts, that would be good to get a little of the perspective among the southern California utilities. If we're going to have any chance of staying on time, and also have a chance for some conversation among the panelists, we can move through the slides quickly; that would be helpful.

MR. COCKAYNE: Hi, I'm Mike Cockayne from Los Angeles Department of Water and Power, and load forecast supervisor there.

I also looked at the heat storm and it just kind of confirms the last two speakers. I broke heat storm into two factors, intensity and duration. I weighted them equally, and I found that this July 6th heat storm was the number one in our history; actually '98 was number two. So there may be some argument whether or not I should weight equally intensity and duration, but I think this data confirms what we saw in the previous two speakers.

My duration, another thing that I would

like to show on my duration curve and how I measured it, what's happening in the LA service territory is in the past ten years we have not seen any days of duration that it's been very hot, and then 2006 with the summer not even completed, we were back up there. So maybe it was lulling us to sleep a little bit.

And my other curve is intensity. You can see during the last 10, 15 years we haven't had very many events in intensity.

So, just looking at those two charts, just as a statistician I can argue, kind of reverting to the mean-type argument, and I would expect in the next 10 to 15 years to see more events, longer duration and more intensity.

And then if you have a theory of global climate change, you know, adding to that, those accommodations, I think it would be very wise to plan at the utility for more heat events in the future.

So that was just my conclusions on that.

There was a question about regional weather patterns, and I think, again, the last speaker cleared it up for me when he said that during extreme weather events there's a broad footprint.

So, in general, LADWP's peak does not peak with the Cal-ISO, it's not coincident. Yet, during these extreme events, it seems to happen. That occurred in '98 and 2006. I say if you needed to study, but it appears that other people are already doing it, so that's kind of what we found.

We do, and my demand forecast methodology include the humidity heat build-up effects. And we've got three different weather stations, so we are incorporating it.

ASSOCIATE MEMBER GEESMAN: How far back does your historical data on humidity go?

MR. COCKAYNE: Well, for the peak day, itself, I have it back to 1966, so I can model those events. But if I really wanted to look at daily humidity data electronically that I have available to analyze, I really only have the last ten years.

So, in those first curves, those were all just mean temperatures. That's why I kind of ignored the humidity in that effect. I just, from '66 to 2006, which is my entire weather database, I only have humidity -- for all the days.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. COCKAYNE: I'm not going to get in -- this is how I model, and I'm not going to talk to you much about that.

Assumptions to be challenged in load forecasting. Los Angeles, a three-day heat storm is kind of our view of the world. In fact, during the heat storm I heard a weather forecaster on channel 4, one of the stations, he said, "Well, this is not typical of the three-day heat storm that we're used to."

And our whole model is built around that three-day heat storm. And yet, in this occurrence, we have three different climate zones in L.A. The Civic Center and LAX kind of exhibited that three-day heat storm pattern. The problem was in San Fernando Valley, as measured by our Woodland Hills weather station, we had 36 consecutive days above normal heat. And that average was 9 degrees above normal. So an average 104 degrees during that 36-day period, average maximum temperature in Woodland Hills for that time of the year is 95 degrees.

So, as a forecaster, when I'm going to be doing in my load forecast is really look at the duration element and try to model longer durations into my weather variables to see if I can't get a more accurate forecast.

The other thing that we do at LADWP is we often talk about saturation in the peak demand. And in April of this year I wrote a memo saying I believe that the saturation was 6000 megawatts for 2006. That was the highest level that our system could reach.

And my actual published forecast, which is done in October 2005, we published our highest case as the one-in-40. And we had, my highest forecast was 59 -- over 2005. And of course, our actual peak on July 24, 2006, was 6102, which really beat my forecast. Even my view of the world going into this summer that we could even reach that number.

And actually the people that I talked to were actually below the 6000. And I had some people -- 5800 was our maximum and stuff. So, in my mind, as a forecaster, every April we talk about this, what is it the maximum we could reach. And I don't think our models address that.

And we've been looking at alternative models. I don't think right now is the proper placed to look at it, but that's really an assumption we need to look at.

If I, as a forecaster, can tell you the ultimate max a system could reach in any given year and managers of the other planners that work around that --

MS. JONES: Could you explain one more time what you were referring to when you talked about the system saturation?

MR. COCKAYNE: I have this other graph; this is the comparison, the hourly loads on '98 versus the 2006. Well, we believe that there's -- the saturation is when all the potential equipment in the service area is on that's going to be turned on. And that the equipment is cycling at its maximum capacity. So air conditioners, they go on and off; maybe they're running 50 minutes out of the 60 minutes.

So what happens is you lose diversity in that system. And so theoretically there's a maximum load that your system can hit. And a lot of our belief about that evolved around the '98, because you see in 1998 about 1:00 in the afternoon we kind of hit a peak, and we did not go much higher after that at that point.

So that, you know, was our firm belief that there's a ceiling out there that the system could reach. In 2006 at 1:00 we reached that point again and we continued to climb.

The thing that that saturation does is that goes into my model. I have a spline methodology, in that once you get past 95 degrees in my model then the response -- per degree actually reduces. So that from 90 to 95 degrees we say we're going to get around 100 megawatts per degree. From 95 and above, in the model that I built in October 2005, we said well, after 95 degrees that levels off to 72 megawatts per degree.

But on the 24th is above the 95 degrees we got a response of 166 megawatts per degree. And that's what we found remarkable; there was quotes in The L.A. Times that we were surprised. Well, that was one of the surprising things to us. Really in our belief and how we model our system, we really believe in that ceiling. So for that to go up, the thing about that is it's hard for me to imagine that if it was 2 degrees hotter on that day, we would have got an extra 300 megawatts beyond the 6102. So that 6102, I mean you're nearing that.

So how to predict that and how to forecast, like I say, that's the forecasting and what we did, we were trying to do.

I think that one of the things that surprised us in this, the other surprises, is that a lot of the load came from the residential. And seeing that PG&E peaked on a Saturday and Sunday, I mean the residential load was just huge during this heat wave.

And the interesting thing that our load research people found out was that between 1998 and 2006 the noncoincident demand in their residential sample has grown by 30 percent. Well, our residential sales growth overall has only been 10 percent. So there was a big, you know, we're losing load factor in the residential sector, which I think was surprising to me, as a forecaster, because I thought with all the energy efficiency we've been putting in, all the distributed generation, that actually were taken away from the peak.

So that difference, I mean I can see a little difference, but that was a really wide difference. And I read in this -- utility that other people were having the same problem.

So my solution to that is really we need a LADWP that will really work harder with our load research and load forecast, to try to capture that change.

I was, in addition to that I would say in the commercial sector we didn't see that much growth. I think we're doing a good job, and I think, in that sector I think that the energy efficiency technology has really held. So I think the problem was in our residential sector.

One of the final questions was weather forecasting. And, you know, I think on a system level for a marketing, wholesaling, maybe put weather forecasting into the models, but for long-term forecasting I don't believe we should incorporate weather forecasting. I think what we do now is sufficient.

MR. GIBBS: Great, thanks, Mike. Any questions?

ASSOCIATE MEMBER GEESMAN: I had one. If you could speculate about residential air conditioning. Do you think that what you're seeing is a more intensive use of air conditioners by your residential customers, or a greater number of air conditioners within your service territory?

MR. COCKAYNE: I think it was both. One thing about determining the number of air conditioners is one, we only do surveys incrementally, so we have, you know, data, you know, every four years, I believe, from the Energy Commission surveys, and also you have the -- housing survey.

So I think we're getting more surveys because of -- air conditioners because of the well known fact that people are putting -- right now people are remodeling their houses. There's a high wealth of factoring due to the housing impact. So there's probably more out there than we're capturing.

And then the second part, given the higher humidity, I believe during the higher humidity air conditioners cycle more. So with more out there, and they did work harder, we believe, during this. That's our opinion. I can't --

ASSOCIATE MEMBER GEESMAN: Sure, thank you very much.

MR. GIBBS: Great. Thank you very much. While we're in southern California, perhaps Tim

Vonder from SDG&E. I understand in some of the materials you submitted that SDG&E viewed this event as about a one-in-25 event. And without going into the whole thing, your comments relative to what the other folks have said, and whether you're seeing something that's consistent in your areas.

MR. VONDER: Okay. I'm Tim Vonder, SDG&E. And beside me here is Greg Katsapis, SDG&E. And Greg's our ace forecaster, and he has all the detail.

I'd like to, before Greg speaks I'd like to kind of -- I'll lead into our little conversation here, and then Greg can take over and get into the detail.

But, we have some very interesting things to show. It's interesting from both a weather standpoint and from a customer-response standpoint.

It seems to be very consistent with everything that we've seen so far today, from those who were speaking about the weather, and also our fellow from LADWP, who was beginning to speak about the forecast and customer responses.

I can tell you that in San Diego our

weather was much hotter than we normally see, which is consistent with the other service territories. We had a July that was overall, talking about the entire month of July, about 6 degrees hotter than the July that we experienced in 2005. And I think that's consistent with what you've been seeing.

The other interesting thing is our customers responded -- well, first of all, the weather was unexpected, but our customer response was expected. They responded just about exactly as we had expected they would respond to weather of this nature. And you'll get a chance to see that, too.

So, with that I think I'll turn it over to Greg, who has a few graphs to show you.

And then I guess one other thing, in terms of customer overall response over the long term, I think you'll see that when we had the crisis in 2001, there was quite a customer response to that. But that time has now passed. And I think you'll see that customers are right on track as they were prior to that time period.

So, anyway, take it away, Greg.

MR. KATSAPIS: Just very briefly, this

is what SDG&E's temperature looked like. It's a weighting of -- I'll try to get -- it's a weighting that includes maximum temperature, minimum temperature, humidity. We use the heat index, so we used a combination of humidity, hourly humidity, and hourly temperatures. We don't take the max and, you know, use minimum humidity. We use coincident humidity and temperature on an hourly basis.

ASSOCIATE MEMBER GEESMAN: And what's your historic data file look like? How far back does it go?

MR. KATSAPIS: Well, we have very good information on two of the three weather stations, air fields and then the third one's a little sketchy. So we go back about 30 years, hourly information.

So we combined that. The top graph represents what we looked like on the day of the -- so this is just, once again, using the heat index formula. And you can see that we were, by far, higher than any other day of the peak that occurred in history.

The bottom graph shows, the red line represents our one-in-ten scenario. The bottom graph here shows that we were pretty consistent with what we saw in 1984. Now, generally speaking, I don't see a big difference between the use of dry bulb and humidity on the energy side; but on the peak side we definitely see a difference.

So for example, this year we noticed about humidity gain, probably about 4 additional degrees. So at 100 megawatts per degree or maybe in our sense about 2 percent per degree, that's a lot of difference that it explained.

In 1989, for example, the actual heat index, it was a Santa Ana condition and the heat index actually was 5 degrees below what the dry bulb temperatures were.

So we find the heat index to be a significant explanatory variable for peak. Not so much for energy, because this is very little difference.

I think the gentleman from LADWP, this is our historical residential use per customer. And if you have a yardstick I could put it up there, but it's not stopped. After the crisis we've had four years of consecutive record growth, and I think that translated into a lot of our summer peak this summer, because the residential sector was a very important factor.

This is looking at energy. Once again here we use average daily temperature or cooling degree days, same difference. And we had a 22 percent increase in residential usage versus last year. We had a 10 percent increase in nonresidential use per customer.

And the top scatter plot here shows the blue dots last year, versus the red dots this year. And you can see the difference. However, it's a pretty nice looking slope if you connect those dots.

This is trying to combine everything into one picture on a two-dimensional graph, similar to what Tom did. The weighted temperature, once again, includes maximum temperature, minimum temperature, not daily average but it's more like 75/25 weighting.

It includes the heat index as opposed to maximum dry bulb temperature. And it takes into consideration prior days and minimum temperature.

So basically I just plotted that one simple variable. It's a little bit more complex within the models, but on the two-dimensional graph this is what you get.

SDG&E actually peaked on the Saturday. I don't know if any other utility's ever peaked on a Saturday. But we peaked on the Saturday. So the blue dots represent weekdays. The red dots represent Fridays. Now, generally speaking, Fridays for SDG&E have been about 1 to 2 percent below all other weekdays, people going home, whatever. But the residential sector made up for that this year. We don't see a big difference. We see some of them above, we see some of them below.

By the way, the yellow dotted line is our forecast for this year. So that's our -- the horizontal line is -- the vertical line, excuse me, is our average temperature. That's our first dot. The next dot is the one-in-five. The next dot is the one-in-ten.

There's a bunch of black dots down there. Well, those are days when, if we're relating it to temperature, I found all those black dots, which fell noticeably below, those were days when we had nearly 100 percent cloud cover. So it's not just temperature, it's kind of hard to mix all these things into a two-dimensional graphic. But certainly you see that six out of the seven points that are below the line noticeably are due to cloud cover.

The last data point on the right, the two green dots out there, that represents our Saturday peak. And, of course, everything else held constant, the actual peak fell well below expectations given the 125 scenario.

But if we adjust that for the outages that occurred, a couple percent; and we adjust that to a weekday, we would actually fall slightly above the line.

Now, we've had about ten years in a row, eight years in a row. We have to come up with these scenarios. I have two data points to work with over the past eight years. Those are the only two data points that we've seen for the last eight years that fall to the right of average. So that's the difficult task that we forecasters have. We don't have a lot of data points out there to work with.

But in terms of coming up with a normalization for this year, I think it's reasonable to say that we're relatively on track relative to the forecast. And in terms of the extremes, I think the top green dot lends some credibility to the extension of that line.

ASSOCIATE MEMBER GEESMAN: You mentioned your outages. Have you correlated those to your peak hour?

MR. KATSAPIS: Yes. We had about 40,000 customers out at a time of peak of the 1.3 million customers.

ASSOCIATE MEMBER GEESMAN: And would you attribute a megawatt number to those customers that were out?

MR. KATSAPIS: It's about 150 megawatts, 125, 150 megawatts out of 4000.

ASSOCIATE MEMBER GEESMAN: And those were all distribution system related?

MR. KATSAPIS: Most of them, yes.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. GIBBS: Great, okay. Thank you very much, Greg. We are sort of coming to a close due to the time for this particular panel. I would like to just get some discussion going about some of the issues and whatnot.

I know Art Canning is over there wanting to say a few words.

MR. CANNING: A little eager to say

something, yes. I'm Art Canning from Southern California Edison. I'm the manager of the demand forecasting group.

I don't have any slides, but you've seen about all that you need to see. I'll say that for Edison we were sort of the cool boys of the neighborhood. At a maximum we hit probably a one-in-temperature on Sunday and Monday.

I've looked at the maximum temperatures for the day, the average temperatures for the day, and then a three-day moving average where we multiply max times the min to get the effective humidity. We've pointed out that humidity and minimum temperatures seem to run hand-in-hand.

And in all cases we're in the one-to-12, one-to-13, somewhere around there. Whereas PG&E, I saw, I calculated is probably one-in-80, ISO one-in-50, something like that on some of those days. So we weren't as extreme.

We've had seven other -- no, five other days in the last 42 years that were as hot or hotter than Monday, the 24th -- I get my days mixed up -- on the Monday in question. So it was not unprecedented, either in terms of maximums, minimums, humidity, whatever. It's happened before. About once a decade, certainly.

What was unprecedented was July was the hottest July on record. And I think we showed that earlier, we calculated July as being like 3.5 standard deviations above normal in terms of average temperature.

What happened was it hit people's bills. So the biggest temperature effect of this heat storm, the most amazing thing we saw was we didn't hit the peak that we thought we might have hit, given the temperatures. We're probably 1000 megawatts less than what would have been normally expected with those individual day temperatures. And I think this was partly because it was near the end of July and people had already been getting their June bills. And most of them had gotten a July bill. And were going into some sort of bill-shock. This is my supposition.

The bills were climbing every day as people saw their bills. And I think that, combined with all the conservation notices out, I mean all the freeway signs blinking FlexYourPower, people really did back off that last half of July. It doesn't seem like the temperature-to- load response maintained its normal coincidents.

So the peak day was not unprecedented. What was unprecedented was the duration of heat leading up to the peak day, which in this case made people very bill-sensitive on the day of the peak, which we never would have thought would have happened. But usually, as we've heard before, we expect like a three-day heat storm and the bills don't build up that fast. But they'd had all June and a lot of July.

The temperatures were not unprecedented. The forecast actually turned out fairly good. Our actual peak was just a little bit under our one-in-two forecast. Now, that was on Tuesday. On Monday we interrupted; and if we hadn't interrupted the peak would have come in a little bit above the one-in-two forecast. But definitely at least 1000 megawatts below the one-in-ten temperature forecast. And it was a one-in-ten type day.

So there was a lot -- customers' response to temperature just became a lot more uncorrelated toward the end of July. And you'd call it conservation, I think is the best thing to say. And I think it was probably bill-induced, or unless somebody comes up with something else.

The other thing to mention, the climatologists talked about it, too, was we use 42 years of data. When we plot the winter minimums and winter average temperatures there's definitely been a long-term increase. The trend is there; it's significant. There's definitely a time trend upward.

When you look at maximum temperature of summer, and this effective temperature, max times min, there's barely any sort of a trend, and it's not statistically significant. So, so far the climate change or heat-island effect or whatever is going on, is definitely affecting the average temperatures of the year, and especially the winter. But doesn't seem to be affecting the day of the peak. We haven't seen a definite upward trend in that at all.

And in terms of -- you asked about air conditioning. My calibration point is Home Depot. And when Home Depot in 2003 started throwing out room air conditioners for under 100 bucks, I figured something has changed here.

I haven't seen the -- and I think Tom supplied us, or CEC supplied us with air conditioning unit sales in all of California. And in the late '90s they were running, I seem to remember, 200 to 300 thousand. In 2003 and '4 I think they hit 500 and 600 thousand. And I'm waiting for the 2005 data. And we won't know 2006 for awhile, I guess.

But I think the room air conditioners, that use has gone up. And that's increasing the residential response.

But, like I said, apparently if people were running that a lot and had already gotten a bill, they responded to the bill, also.

So the saturation is increasing, I think, from these sales. I don't think this is just replacement of old air conditioners, I think some must be new use.

Those are my comments.

MR. GIBBS: Okay, thanks. Am I correct in listening to your comments that of the other folks who have spoken so far, yours was the only circumstance in which load turned out to respond less than what you otherwise would be expecting, is that correct?

MR. CANNING: Yes. Seemed like everybody else was surprised at how high the loads got. We were so surprised that they didn't go higher. So, both in the long term and in the short term. In the procurement on Friday when we bought for Monday, we actually over-bought, even without the interruption, I believe. So Tuesday we might have bought under-bought a little bit, but it was pretty close.

So we were -- the day-ahead in procurement forecasting was doing pretty good. And that's a model that can learn.

What we're trying to do here, though, I think, is also level set; what was the weather-adjusted peak demand for 2006, and what we can do a 2007, '8, '9, '10 projection. And so right now I haven't finished the analysis. I really want to see some more September. But I don't think we would adjust it very much. Although it's hard to take into account what this -- affect might have been.

MR. GIBBS: Thank you. Go ahead.

MR. ASLIN: My name is Rick Aslin; I work for Pacific Gas and Electric Company. And I would say that just two overall comments.

One was that for Pacific Gas and Electric service territory it was very much an unprecedented heat wave. It was something that, in terms of an analog year, we hadn't seen since 1972. And even 1972 didn't have the duration of the heat that we saw in July of 2006.

How to place that in the recurrence interval is very difficult. I think the recurrence interval concept probably has some value for one-in-two recurrence type interval, one-in-five. But when you're talking about only having 50 years of data, trying to say that it's a one-in-50 type event, there is no real statistical validity to that sort of statement.

So, I think in terms of things that we could do, I think it would be useful to draw in more of the meteorological community and try to develop some sort of recurrence intervals that are based on more statistical probability theory, taking into account sample size of the data that we have and that sort of thing.

So, I think PG&E would like to work with the Energy Commission on coming up with some sort of statistic for weather and recurrence intervals that both the Energy Commission and PG&E would use for long-term forecasting.

In terms of the forecast performance, my overall view of it is that the forecasting process is not broken. Tom showed that the one-in-20 forecast that the Energy Commission had for 2006, after being adjusted for the experience of 2005 observed data, was actually really close to what we saw in PG&E's service territory for 2006. And that's even after you adjust for our estimates of demand response and of the outages, which added about another 1000 to 1200 megawatts to the observed load.

And the --

ASSOCIATE MEMBER GEESMAN: Rick, let me take some slight exception to both what you and Tom said about the process. And I'm not suggesting the process is broken. But I would suggest that we probably exist in parallel realities.

And I understand from a forecaster's perspective you guys are probably most focused on the actual results. But let me tell you from a state government decisionmaker standpoint, I don't particularly care about the actual result. What I care most about is whether the process will help inform better decisions or avoid poor decisions.

Now, we have a process, or a calendar, if I can call it that, which, in this circumstance, did not correct for the fact that 2005 demand statewide, or I should say ISO-wide, was 2000 megawatts more than on a weather-adjusted basis we had thought it would be. We didn't catch that until May.

And you were here at our workshops. It wasn't until June that the Energy Commission actually revised its forecast for 2007, and we backed into numbers for 2006, which everybody takes some pride in, as being reasonably accurate in predicting 2006.

But throughout the fall of 2005, the winter of 2006, the spring of 2006, the state decisionmakers were fed a cocktail of, if you will, muscle relaxant, antidepressant --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- boosters. We didn't have anything to worry about in the summer of 2006 all of our best analysis suggested.

And from my perspective, I think there is something flawed, not with the process and with the calendar, that prevents us from making judgments that can possibly lead to some corrective action between the summer of 2005 and the summer of 2006.

MR. ASLIN: Well, I don't disagree with that. And I certainly agree that the whole purpose of the long-term forecast is to inform the decisionmaking. And that those decisions are decisions that are made that put in place infrastructure that's going to be around for a very long time. But fully would support any sort of change to the calendar that would have more frequent updates of forecasting and that sort of thing.

ASSOCIATE MEMBER GEESMAN: I certainly appreciate the degree to which you guys have been willing to share data and share analyses. I think that's a lot more helpful to us than some of the anecdotal observations that we sometimes hear as to what's driving demand.

MR. GIBBS: Great, thank you. We kind of haven't heard from the ISO.

MR. EMMERT: Well, looking at my watch we're about out of time, so I won't show any slides. You've seen a lot of weather data.

But one thing I did have a slide that I'd just like to speak to in the area of the fact that the resource adequacy program at the ISO is based on the one-in-two forecast. And the load-serving entities go out and buy 115 percent of that amount, which came in pretty close to what we actually needed at time of peak.

I agree that our forecasts were pretty accurate. We actually forecasted within a few hundred megawatts of the actual peak if you would have looked at that particular forecast.

But the thing that I see an issue of concern is not the forecast, but how we go about procuring capacity based on those forecasts. With the one-in-two forecast and buying 15 percent over that, we pretty much chewed up all that 15 percent cushion just in going above the one-in-two forecast.

If we would have had any substantial amount of transmission or generation outages at that point in time, there wasn't any cushion left for that. So, I think that's an area that I would focus the discussions on in future.

MR. GIBBS: Great, thanks, Bob.

MR. GORIN: I'd like to make a comment regarding Commissioner Geesman's statement. I think from the major part while I've been tracking the ISO on a daily basis, and the relationship between its loads this year versus last year, is to try and alleviate some of that surprise.

If our forecast, if the daily forecast would have been, you know, consistently below what's experienced, I don't think we'd all be here saying, well, our forecasts look okay now.

But that has just transpired in the last year. We still don't have loads from the individual utilities. We put out a data request that are being replied to now, to look at what the forecasts look at in an individual level for this summer right now.

But we're trying to shorten the time period at which we come up with surprises. And hopefully we don't come up with surprises.

ASSOCIATE MEMBER GEESMAN: Yeah, I understand that, but we've got demand response goals that we have not successfully met since they were first set four years ago. And we continue to under-shoot our performance targets there.

We've got a fairly listless approach to the long-term procurement. I think that we would bring a lot more urgency to these topics if we had known sooner than May of '06 that demand in '05 was 2000 megawatts more on a weather-adjusted basis than we had thought that it was.

MR. GORIN: Right, I don't disagree with that. But at that point in time, that was the earliest that we could have credible information from the utilities. Now there's more of a sense of urgency and we're getting it on a more regular basis.

MR. CANNING: If I could add, Commissioner Geesman, last summer was unique in that 2004/2005 was a very high growth rate for Edison, and I think California, in general.

And from our data it looks like things have slowed down. But, the CEC didn't have the 2005 data in time to do the forecast, the hourly data for the summer of 2005. If they had had data through August when they came up with their September forecast, they would have seen what was going on and that would have corrected it.

So part of it was just a data lag. And you fixed that process now. We just sent in data up through July 2006. So, I asked Mr. Gorin if he spent the weekend analyzing it, and he said, no, he's not because there's confidentiality issues. And I appreciate that.

But when he looks at it I think he'll find out, whoa, what was going on in 2005 may have slowed down, but we had a unique weather event, too.

But what's happened, I think you've changed the process now. The CEC will be getting actual hourly load data in time to not be caught unawares as they were in the summer of 2005. I think that was a unique event.

And I think the opposite is going on now. I think it's probably slower growth and they'll find that out now, too.

So, I think that process has changed. We could see it. We updated our forecast back in October 2005, more to what the CEC came up with in May and June. So we knew that was coming. And it was just a simple analysis from the 2005 data.

So, I think that part of the process, you've got the data coming in to where your staff will know what's going on through the middle of summer before they start publishing any long-term forecasts. And I think that's a big important part of it, too. So, that, I think, you have fixed.

ASSOCIATE MEMBER GEESMAN: Well, I think the disparity between what you knew in October of '05 and what we didn't know until May of '06 is problematic. I also think that these types of discussions are much better informed when they're conducted with publicly available data which all of the parties have access to, and we can actually review what your projections are, what our staff's projections are, and hear from others as to where some of the defects in the analysis may be.

MR. CANNING: I would agree, and we did have conversation with the CEC Staff back in the spring telling them we thought the numbers looked quite a bit off here.

But I think you've got your publicly available data now. So, that process is -- that's why I say it looks like the process is going on to where you'll have the data in time to make the decisions you need to make. And I think that's important for you to have. And I'm glad we're through the confidentiality issues and on with planning.

MR. GIBBS: Well, thank you very much. I'd like to thank all the members of the panel who contributed. From this discussion I take away that this was an, if not unprecedented, extreme event certainly. And unprecedented in some areas. That the load forecasts by the utilities in particular were reasonable. And while there were some surprises, that overall we understood more or less what was going on.

And then thank Bob for his comments toward the end, leading us, really, as a segue to the next panel on system reliability.

So, what I'd like to do is thank the panel again. And ask the next panel to please come up and take your spots.

(Pause.)

MR. GIBBS: All right, thank you very much, and welcome to the panelists in panel 2. I think what we'll do here is we'll first go around and have everyone introduce themselves briefly. And then we'll have Jim Detmers give us an overview presentation. So if you can just quickly introduce yourselves.

MR. DETMERS: Certainly, Jim Detmers, Cal-ISO.

MR. DASSO: I'm Kevin Dasso with PG&E.

MR. HOWARD: Randy Howard, LADWP.

MS. KOEHLER: Birgit Koehler, Bonneville Power Administration.

MR. KELLY: Steven Kelly, Independent Energy Producers Association.

MR. ANDERSON: Robb Anderson, SDG&E.

MS. JONAS: Junona Jonas with Silicon Valley Power.

MR. SCHOONYAN: Gary Schoonyan, Southern California Edison.

MR. GIBBS: Okay, thank you. Our panel two is system reliability, and we're fortunate to have Jim Detmers from the California ISO to start us off.

MR. DETMERS: I'm going to stand over here; try something new here.

Well, thank you very much, Commissioners, Commissioner Byron, Commissioner Geesman. My name is Jim Detmers and I work at the California Independent System Operator. Still in its existence for the last almost nine years now I've been there. And happy to say that I think we've made it. And I hope we can continue to say that over and over and over again. But it was not without a lot of challenge here over the last few weeks back in July.

We did have some very interesting times to deal with and that wasn't just at the ISO. This has been -- and I'll go down through what the day was like, what some of those days were like, as we hit our peaks. And I do have a few slides up here.

But really what it all comes down to is there was an enormous amount of preparation. There was preparation and execution both coming together on an industry front, not just at the ISO, not just a the generators, not jus at the investor-owned utilities and the municipals and everyone else. It was every single element in our industry, including regulators both at the federal side and the state side, had actually pulled together to make happen what actually occurred here in the last few weeks.

It all goes back down to basically hitting a condition on Monday, July 24th, which was the all-time day. You always have to look at the record. That's when we crossed the tape and we made it across the finish line.

And we were able to exceed our system peaks of what we've seen in the past, both in terms of energy use, as well as peak demand.

July 24th was actually the eighth consecutive day with temperatures above 100 degrees for California. It was also a heat wave throughout the west as the weather forecasters have indicated. And there were several control areas, these are the entities that balance supply and demand in the west. Several, I think there were over six control areas actually in energy emergency alerts. These are what are referred to as EEA or what we refer to as a stage 1 or a stage 2 emergency. But they were actually spread throughout the western United States.

On the 24th we reached our system peak demand of 50,270 megawatts. That was 4839 megawatts higher than our 2005 peak, which was 45,431 megawatts.

So, we actually grew by close to 5000 megawatts just within one year. And that was not just because of the temperature conditions; that was because of load growth, as well, in California. The economy is still growing. We're still seeing it coming on.

And we would expect that to continue into next year, that load growth on the system. Our average yearly peak demand actually grows by about 1000 megawatts a year. And that's what we have to keep pace with, both in terms of growing our resources, whether they're in controlling the demand on the demand side, or they're actually new generation coming on, and maintaining the existing fleet, as well.

Another point that you need to be aware of is WECC, the interconnection, the Western Electric Coordinating Council, also hit its peak demand. This was 152,007 megawatts on the 24th, as well. That was 13,162 megawatts higher than the 2005 peak. So that was a growth of about 13,000 megawatts WECC-wide.

And again, temperatures westwide were the primary driver behind what was happening on there. But, again, we're seeing load growth happen outside of California as well as inside of California.

To go back to my previous comment on how did we do it, because I'm asked often what happened. How did you do it. How did we do it, and what contributed to that.

And so I'd like to refer to it as our investment made over the last five years has actually paid off. And this was an investment in preparation. We coordinated on the days coming up to the 24th. We coordinated with the Bonneville Power Administration on making sure that their dispatch of their generation and their grid was maximized, to maximize capacity into California so that we can get through that day.

Massive coordination, I've got thanks to give there. I've got thanks all the way around this table, probably all throughout this room here, that I have to thank. There have been an enormous amount of coordination, collaboration, cooperation, all the different Cs that come into making this happen.

We worked with generators to optimize their maintenance schedules. We coordinated through numerous calls to make sure that everyone was fully aware of what was happening, when it was happening; and I think that cooperation on those calls and that coordination on those calls really paid off, as well.

There was an enormous amount of relationship building with Department of Forestry, CDF, that is, California Department of Forestry, the Public Utilities Commission, your Energy Commission, the municipals, again, power plants. All of that really came together.

Summer preparedness seminars where we actually had all of the entities throughout California, all of the transmission operators, including, I think, Bonneville's operators on the transmission side, within training seminars; going up to lead up to this summer. All of that, again, paid off.

Actually going through the actual day, conservation and demand response also paid off. And a number of other things that all kept coming together.

Regarding the previous presentation on forecasts, I think our forecasts were really good. I don't see that as being an issue. I think that's an evolving science that needs to continue its course like it always has, with regard to load forecasts.

But I do think we have to start to take a look at supply forecasts, not just load forecasts. And making sure that we truly understand what's behind the supply forecast is the other massive side of what it takes to make sure that we can keep the lights on.

And, again, on most of these areas I would like to say that I believe that we actually exceeded expectations. So I've got my top ten of areas of exceeded expectation, and I'll just rattle these off, since I've already mentioned a few of these.

But starting out at number 10, our imports were higher than expected. We were actually sitting at 9600 megawatts of imports on that day, on the 24th. While our forecast was over in excess of 10,000 megawatts. We were very very fortunate, and it was again all the payoff between the operators and the coordination that got it up to that 9600.

Number 10, the interruptible customers responded. And they actually responded upon our declaration of the stage two emergency, before the utilities actually made their dispatch call out to call on those loads to come off.

We saw an enormous amount of conservation that was there, and that's number eight. Customers responded. And I actually happen to live in the community here in Folsom, California, that my neighbors told me, well, we saw you again on tv, Jim. And I said, oh, you did. And they said, yeah, you were threatening everybody again. I said, I didn't threaten anyone.

And what came back was we need to figure out how to get the right message out, because it's not that we were threatening. We had conditions to deal with; we were dealing with the fact and the reality of what we were trying to manage. But the consumers stepped up and, again, I owe some thanks on that front, as well.

Number seven, load forecasting. Our load forecast was off on that day only about a half a percent of what we're estimating. And we've actually gone back in, factoring in the 2400 megawatts -- or 2400 distribution transformers that probably simultaneously added to about 200 megawatts of actual load off the system. These are distribution transformers that failed. But the load forecasts were accurate. That's the number seven.

Number six, I've got to take credit for getting all the real-time operators, the operators on our floor at the ISO, the operators in every single one of the generators on the grid and throughout the west were actually operating at top performance.

And at this time I'd like to recognize Mr. Lonnie Rush sitting right behind me, here. He's our manager of our real-time operations. Lonnie and I lived in the ISO over the whole entire Friday and through the weekend, and through that Monday and Tuesday. And, again, it's people like this with the dedication.

And it's really this overall industry that is dedicated on the operators' side and all the constructions -- here. Again, I'm getting choked up as I talk. But it's all the dedication that really paid off.

Number four, coordination. Actually I have coordination and cooperation and collaboration. This is CDF, US Forest Service, the ISO, the PUC and the list goes on and on and off the page.

Number three is the transmission grid performance. I haven't talked about that, but we did have some problems earlier on in coming into this year with the operation of the Pacific DC Intertie. It was actually tripping and operating due to eagles nesting in the tops of the towers. But with coordination with LADWP and with the Bonneville Power Administration, there have been no operations of the DC whatsoever going throughout this summer. Thank you very much, Randy.

But the line availability throughout the system was outstanding. The system did not experience congestion. We were operating at peak loads, and the system is designed to actually operate up at those peak loads. We were actually exceeding the design areas of the distribution system, but again the transmission system was operating.

We did have a few voltage problems in certain areas in northern California. But those, I'm sure that the engineers, both at PG&E and the ISO, will take care of. And we also had a few, but no major normal overloads on some of the smaller transmission system.

Number -- where am I at, here -- number five. Hydro production was at all-time highs. Hydro production in northern California, as well as the Northwest, was at maximum conditions.

And the last two, the last but not least generator availability and generator turnarounds. Generator availability was at an all-time high, as well. As well as we did see the turnaround of units that actually responded and got them back online within one night turnaround times.

And lastly, probably most importantly, and I did have to rank these, too, somewhat, I would have to say most of these are all at the same level, all at the top, but I think we actually had a top performance of the market.

And this was scheduling this had to do with the Public Utilities Commission enacting the resource adequacy proceeding; and getting in what I would refer to as an obligation to -- a financial obligation to deliver power.

Back in the years past, and before 1998 we had something called an obligation to serve. That's what the utilities did all of their business under.

Now what we have, what was just instituted is a financial obligation to deliver. That is what we saw in the performance of the generators that I referred to in number two. And scheduling in the day-ahead market was 95 percent of the overall peak. And in the hour-ahead it was about 99 percent of resources that were being arranged prior to coming to the ISO.

That is what made the difference, along with everything else that I just mentioned. So, again, it was a difficult time, and I'm always, at least at this point, I normally don't give thank-yous out, but I'm forced to this time.

So, again, thank you to everybody in the room, and to the Commission, as well, for all the help. Let's start looking forward as to what we need to plan for. And I agree, Commissioner Byron, we do need to learn something from this and see if we can repeat this again.

Thank you.

PRESIDING MEMBER BYRON: Great, Jim, thank you very much. If I could I'd like to just interrupt with a quick question. And I'm not sure if you're the right person to answer, so you can punt on this if you want.

I really appreciate your list. But I'd like to go back to the load aspect of this. This may not be the right place to ask it, but I don't think it was the previous panel, as well.

Understanding this load a little bit better. You said forecasts came in very close, very accurately. But yet there seems to be something going on with the load, primarily residential load, that we don't understand very well.

And I don't even know quite how to ask, because I think it might be an outcome of this workshop, that we might need to do a better job of understanding what's going on there, what's delaying that peak with the residential load? What's the effect of humidity? Because there is a mechanical effect, as we know, on air conditioning that's treated by that.

But, anyhow, Jim, I'll leave it open to you. Is there anything you can contribute to that?

MR. DETMERS: Commissioner Byron, I think you just did a very good job of starting to frame what we really need to study more going forward, and really understand, and take some time to really understand what's behind the load on the system.

It's there, we are seeing changes. Marked changes in exactly what we're seeing, both in residential, commercial and industrial. Residential in particular, we are seeing a marked change of how it actually responds on the system and how much actual demand is actually behind those distribution circuits that are out there in the field.

I don't think we can answer that today. And I don't even think that that's probably something that the ISO can answer, but really takes some coordination back with the utilities to really dive in and find out what's behind that connection.

I know there was a reference to the buying of portable air conditioners during the heat wave. We did have discussions with both Home Depot and Lowe's, and I'm not advertising by any means, but especially if you're going to go buy an air conditioner, I'm not advising that.

But they did sell out. Most of the areas, both in northern California and southern California, they sold out of those portable types of equipment. And I think the overall connection of load I think is definitely there, of additional load. We just need to understand that better, though. And I think you're on the right track.

ASSOCIATE MEMBER GEESMAN: Jim, do you think that your congestion picture was actually helped by the fact that this was a statewide phenomenon. Might it have been different if it had been more of a regional heat wave?

MR. DETMERS: Yeah, I would agree. I do think, Commissioner Geesman, that the heat wave, because it was throughout the state, did not result in congestion say at Path 26 midstate. It did not result in other congestion locally.

And we did see, and I don't know whether the forecasters mentioned this or not, I may have stepped out, but northern California was defined in an above-normal condition as compared to southern California. The heat, and again I'm not the expert on the forecast side, but because of that distribution between northern California and southern California, as well as the resource mix, we did not see that.

If we were to have, though, a condition just within one of the large zones, one of the large areas which are the size of other states throughout the nation, we could see congestion; we could see particular issues on those portions of the grid.

So, again, I'm not saying that the grid is okay, because even as we go, or it's sufficient so we don't have to invest into that. I'm not saying that at all.

In fact, I do think the investment into the grid came at the appropriate time. We completed the upgrades. Southern Cal Edison completed the upgrades of the Devers capacitors and other things that came in in June. That

investment is what actually was fully utilized as
we walked through the summer.
So, again, we have to keep up with the
pace, almost get ahead of the pace both in terms
of transmission and so some of my thinking goes
along the lines of what can be done to expedite
some of that investment. We need to take a look
as far as expediting, as far as carrying on
normally with that investment into both the grid
and the supply infrastructure throughout the
state. Make sure it's in the right locations.
MR. GIBBS: Okay, great, thank you, Jim.
Any other questions for Jim right now? One of the
organizations that you mentioned, and you
mentioned personally -- was Bonneville. And we
have with us today, Birgit Koehler, who can say a
few words about how Bonneville viewed this event.
And how it related to our experience here in
California.
MS. KOEHLER: Thank you. So I'm from
the power scheduling side, so because of SOC I
don't know as much about our -- side of what
happened, but I thought you might want to hear
what happened just to the north of you, because
we, ourselves, were having a very very interesting

period at that point.

So, for one thing, you need to be aware of is that the Northwest is very highly hydroelectric; 50 percent of the region, Bonneville specifically is 70 percent. And what that means is part of the year supply is no problem. In the spring during runoff we're generating with half the water and the rest of it is spilling because all of our turbines are fully loaded.

But in the summer the flows decrease dramatically. So I'll give you an example. On the lower Snake River we have four projects with over 3000 megawatts of installed capacity. By July the flows decrease to about maybe 1000 megawatts of usable capacity.

But because of fish operations, which I'll describe in a moment, we are only able to generate about 600 average megawatts with our 3000-plus megawatts of turbines. By now in late August we're at 400 megawatts on that system. So that's a dramatic reduction.

So the fish operation, as I mentioned, in 1990s Fisheries said there were -- NMFS, National Marine Fisheries Service issued a biological opinion that really put in place a number of operations that we are constrained to because of salmon recovery efforts under the Endangered Species Act.

And we've also been to court, litigation by a number of environmental groups that have severely hampered our operations. Like I mentioned, on the lower Snake River, almost half of our generation had to be diverted to spilling water to help smolts migrate downstream, spring and summer. So, we've got a lot going on that really drives a lot of the -- on the hydro system.

So what did it look like? We had a hot four-day spell. Our peak temperature came on Sunday; Friday, Saturday were pretty warm, but our loads normally peak on Mondays, so even though Monday was a little cooler, it was the most significant day for us.

The Northwest power pool includes Canada, so they were on the edge of this heat event. The region was only eight degrees above normal, but the BPA control area, we were almost 13 degrees above normal on that day.

A number of outages occurred during the period. The largest one that I'm aware of is

Colstrip unit, almost 800 megawatts that went out, came back, a few hours later went out again. Several other events happened during the day. And all in all, we had six control areas in the Northwest power pool, including Canada, that went into some level of emergency status, all the way up to level three in one region. I believe Alberta; that was transmission was what really put them over the edge.

And a couple of these sold energy ahead to California before they realized that the forecasts were a little low. And they should have saved it for themselves.

So what we were doing as far as major regional transmission, the AC from Oregon to California was delivering about 4000 megawatts. And that was limited by loop flow; really couldn't have put any more on there.

A smaller effect was a couple of cutplanes at the northern end near our John Day region, were near the OTC limits, the transfer capability limits; it couldn't have delivered any more. That voltage event was more significant on the DC, where we were limited to transmitting about 2400 megawatts.

And meanwhile, Canada was sending us about 2000 megawatts, which I assume a large part of that went through us and straight down to you.

Coordination efforts. As Jim mentioned, we were on the phone with the ISO several times; many times on Monday that I know of, and several times over the whole event. Bonneville Power also doesn't own any power plants, no private hydroelectric projects, nothing.

The Corps of Engineers and Bureau of Reclamation own the hydroelectric plant. So, we had to work with them to obtain flexibility. Some of that you can do in one phone call; a lot of that takes a few days notice.

Also, as I mentioned, since we've been under litigation, the Department of Justice is administering court-ordered operations for salmon recovery. And for us to go and deviate from that by one megawatt, or one -- events of water flow, we have to coordinate with them. So we talked to them ahead of time and throughout the, specially on Monday, saying this is what we would need to do under these circumstances so they'd be prepared in case we started deviating from our mandated operations.

Before the Department of Justice was involved, we've always had interaction with something called the technical management team that coordinates fish operations, salmon recovery. And we talked to them several times, too, to let them know what was going on. Because otherwise, after the fact, the mess politically in the Northwest would have been disastrous. Politics really drives a lot of what's going on for us.

So, what did we do in advance. We did a lot of work, some of which was just preplanning. Some of it are things that we can't do all the time; we can only do this once or twice a summer or you wouldn't -- the answer would be no.

But we did get permission to exceed some of our river operations; have higher tail water at the Port of Portland and Vancouver. Permission to draft more water out of Grand Coulee Dam than we normally would.

We manipulated flows over the weekend in particular so that we could set up for Monday morning. Often load generation on Sunday means that you don't have enough water downstream on Monday morning. So we sold power deliberately on Sunday just to help our situation Monday morning.

As you'd expect, we got units back in service; on the bottom half, we had transmission outages. Everything was rescheduled that could be. And some of our salmon operations were able to move around in advance.

Talking to the folks in transmission they said they sharpened their pencils so they really were able to model the grid as accurately as possible to current conditions, and give us as much flexibility for hydrogeneration.

Had we reached a stage three emergency, there were --

UNIDENTIFIED SPEAKER: Had we reached --

MS. KOEHLER: Had you, I'm sorry.

(Laughter.)

MS. KOEHLER: Had you -- had we, as a collective, tried to work through this together -- had you reached a stage three emergency we would have been prepared to do a few things. But only because we talked to the Department of Justice in advance. And we talked to Jim several times. We needed a letter in writing that specified risk to health and human safety before we would have been allowed to do some of these things. Reducing, it's basically violating some of the salmon operations. We had to make it very clear this was only a last resort, but it was there, and it was a good thing we did all this in advance.

So, the lessons that we learned basically, the coordination, as Jim said, coordination was crucial. You can do a certain amount of scrambling when things happen, but the more you can do in advance, bureaucracies in many places, especially the Army Corps of Engineers can be a little slow. And we did a lot of work preparing the River. That really saved our hide.

One of the issues that we did run into is that after awhile when control areas did go into emergency status we stopped what we had initially didn't want to sell power to people who were just asking for it without entering emergency status, so eventually we had to say we can only sell to those control areas declaring emergencies.

But one of our issues is that there isn't a clear common standard. Well, is it the market, or just say, oh, I want power, so let me just call in an emergency; or was it a real documented emergency. So those are some of the things that I think we will need to work on.

But I was amazed at what we were able to pull off.

PRESIDING MEMBER BYRON: Birgit, -- asked you a question or two. Thank you so much for coming here today.

There was a lot of good things that happened it sounds like. You mentioned there was some over-selling in the day-ahead market; the system had a higher capacity for import than we may have thought otherwise; you were allowed to over-seed on generation; good preparation and planning; maybe a little bit of luck.

How much, I mean which one was the big factor? Which one do you think was the biggest contributor to our ability to import, what, about -- was it about 1000, 1200 megawatts more than we expected? Maybe 2 percent of our capacity.

MS. KOEHLER: Oh, the biggest factor, I would say, doing the math, the exceedances on our standard operating range and probably the unusual preparations that we took, just manipulating the river just right. We had one of our least-experienced operators on there, someone who'd only been with us for four years. And still, everything came out smoothly. So I'd say those two are about comparable.

MR. GIBBS: Thank you very much. And, again, thanks for joining us here. I think one of the other points that's been made is that the generators really did well during the event, and perhaps Steve Kelly can say a couple words from IEP.

MR. KELLY: Thank you, Commissioners. Steven Kelly with Independent Energy Producers. I think overall the message here is the generation community was there when needed and performed admirably.

When I look at what just occurred this summer in July, I'm going to step back a little bit and think about, particularly going forward, what we need to do. Because, you know, in 2001 that period of time is called in all the literature and all the speeches about the energy crisis. And it was characterized by a period of low hydro, so imports were affected. Transmission constraints and some generation outage.

Today we're luckily here just simply talking about a heat storm period. But the reason we're able to talk about a heat storm period rather than an energy crisis is because we had very good hydro transmission was full; there were no outages; no fires which were beyond the control; and the generation fleet performed very very well. Everybody way above expectations. Very few outages.

I mean those factors are critical when we think about what we need to do on a going forward basis and plan for the future. And I know that we're talking about forecasting, and some of the comments about forecasting for the next year. But I'm really concerned about forecasting in the long term and what we have to do.

There are a number of factors for planning that I think this Commission needs to be fully aware of that needs to be addressed as we move forward. And one of them is the aging power plant fleet. This state has a significant number of facilities that are relatively old. And the expectation that they are always going to be available, absent some incentive to repower, or a market design that would allow them to recover their revenues is going to be an assumption.

And we don't really have a system to guarantee that either of those units are available or replaced with new efficient units.

The other question that I have is regarding imports. Can we expect in the future that the hydro resources will be there? Can we expect in the future that other regions in the WECC will export to California, particularly if nationally or regionally we're moving to a greenhouse gas emissions program, where cleaner resources like hydro resources are going to be preferred by the local regions so that they can meet their greenhouse gas obligations?

And what impact is that going to have on the ability to deliver other resources to California in our time of need? We've always depended on these hydro resources, which now have potentially some value to retain in the local areas.

So, in my mind there's some key questions that we need to talk about, and one is procurement. And market design is the other, to make sure that we have the proper mechanisms to incent that new generation is installed; that the aging power fleet is repowered, necessary to maintain and provide us.

We seem to be in a system now where we're buying just in time from a procurement strategy. I think the independent power industry is not particularly happy with the way procurement process is being implemented in California right now. We are looking for signals and signs that allow people to invest significant dollars, billions of dollars in California. But that isn't there yet.

From a planning perspective we have been planning for a one-in-two. And as you've heard today, that a one-in-ten scenario was met. And in light of the discussions in the scientific community about the effect of global warming and so forth, is one-in-two planning criteria adequate. Is the 15 percent reserve margin adequate, particularly for the load. Is that the kind of criteria that they want to impose, when it does risk, as we just saw this past summer, a very tight situation. One which we got through because everything fell favorably for California.

And then finally, I'll just reinforce the concern that we are doing procurement in what I call just-in-time procurement. That we are not planning far enough down the road to make sure that needed investment is in place in a timely manner.

And the Public Utilities Commission just released an ACR last week which directed the utilities to build at least 250 megawatts of new generation for next summer. You know, that's an issue that we should be able to deal with hopefully with our forecasting and planning.

And, you know, the fact that our forecasts are accurate five to seven months out doesn't really help from an investment perspective. We're looking for signals from the utilities to state about what you're going to need three to ten years out so that we can plan and build for this.

So, those are my comments.

ASSOCIATE MEMBER GEESMAN: I think, Steven, you're talking to the choir with respect to some of your points. This Commission, as you know, unanimously last November endorsed a procurement program that would repower or replace all of the aging units by year 2012.

And our estimate was that's about 15,000 megawatts of capacity required. In fact, by our judgment, what's now an outdated forecast, but by our judgment the 15,000 megawatts slightly exceeded about 14,000 megawatts during the same time period that we though would be necessary to meet load growth.

But there's a fairly big difference in terms of our perspective, and our sister agencies', as to what the actual needs are. The year 2009 was focused upon by the CPUC's procurement decision last month in the long term proceeding. They determined a need for 3500 megawatts. Our number's 9000 megawatts. And that was without adjusting for the 2000 megawatt difference that we've ratcheted our forecast up. So 9000 is probably closer to 11,000.

Nobody seems to be talking about these disparities or pretty stark differences in perspective. And it seems to me that we indulge a lot of discussion, which you and I have been engaged in in the past, as to market structures. At the expense of, perhaps, losing sight of our prior objective, which is providing the adequate infrastructure of the state's electrical system.

MR. KELLY: Well, I agree with that. I mean we have been advocating for a long time that in California there's, you know, kind of the twin components of incenting the right investment in the right place, market design and long-term PPAs.

And the RFOs that I've seen unfolding so far generally excluded any existing units from it being able to bid into those ten-year RFOs which would provide the resources to repower this aging fleet.

You know, if we had another heat storm in September that we had in July, I mean what's the probability that some of those units that ran to the max during July are either out for maintenance repairs, or finally break.

I have no idea what the answer to that is, but it is a risk. And I think the sooner that we move to a situation where the generation community is able to get the proper incentives to replace that fleet, the better off we'll be. And we're not doing that as far as I can tell right now.

MR. GIBBS: Okay, great, thank you. Just following up on one point you made there is that the fleet did operate well during this particular event. Were there things that you saw or preparations that were made that you felt were most important in contributing to the ability of the fleet to perform in that way?

MR. KELLY: Well, as Jim Detmers

referred to, there was a number of communications between the ISO and the generators, kind of closer to real time, as it is, you know, within 30 days, to get ready and be ready and be available. And I think that communication was very very helpful for the generation community, to be coordinated that way with the Independent System Operator.

And I believe in those discussions the utilities, some of the larger load-serving entities, were involved or aware of. So that kind of coordination was very helpful.

MR. GIBBS: Okay, great. Thank you, again. Kevin.

MR. DASSO: Good morning, everyone. My name's Kevin Dasso. I'm PG&E's senior director of asset investment planning. Actually have a couple of slides I was going to talk off of. I realize the timing is short, but I did at least want to use those to demonstrate really the issues that PG&E encountered in the heat storm.

Well, from PG&E's perspective this event really was a distribution issue. Before I get into that, I do want to talk a little bit about transmission system operations and what we experienced.

In many respects I want to echo what Jim had to say. The transmission system performed very well. That was not an accident. Since the energy crisis PG&E's invested over $1.5 billion in its transmission system to replace equipment as well as expand capacity. And so it's been a concerted effort and we believe it withstood at least this test.

We're not stopping there. The expansion plan that we provided to the ISO early this year includes an additional $1.5 billion to $2 billion depending on if the ISO agrees with us on some of our expansion ideas. And so we're planning to continue to make those investments. We're not stopping here; we're moving forward.

In terms, again, of this particular event, the heat storm, was a distribution issue from PG&E's perspective. And largely, as was touched on a little bit earlier, the biggest impacts were on our residential customers. So that's what I want to talk a little bit about, what we experienced and some of the implications of that going forward.

Okay, this is a picture of essentially the outages that occurred on our system over the course of -- well, from an outage perspective it was the main outages occurred really over three days. The three humps that you see in that curve there are the first, which occurs on Saturday, the 22nd. The next one was Sunday, the 23rd. And then Monday, the 24th.

However, as illustrated here we did have outages continuing for the entire five-day period. Over that period we had about 737,000 customers affected in some fashion or another. About 95 or 94 percent of those customers were restored within less than six hours.

We did have some longer range outages that occurred, largely due to individual transformer failures. However, about .4 of a percent of the customers that actually experienced outages during this period, saw an outage in excess of 48 hours.

So, by and large, the impact was significant on our customers; however, by and large, the outages were not long in duration in terms of the overall impact.

This is a chart and I'll actually show a little bit more of it in a detailed chart. What I'm showing here, the red and blue dots are outages that we saw in our distribution system.

The red dots are individual transformer outages. The blue dots are outages of other types, typically fuses blowing, circuit breakers operating and so on that affected our primary system in some other fashion.

What we've done is overlaid some of the profile line, contour lines that Mr. Marler talked about this morning in terms of the weather event. The three lines that are shown there, the first one kind of closest to the center of the chart is the line depicting really the last time we saw an event like this of essentially a 50-year type of occurrence.

The next contour line there is a 30-year; so somewhere between something greater than 30 years. And then the last line is something less than 10.

What's significant and you can see even better on the blowup, might look just specifically at the Bay Area, the outages along the coast were really pretty minor. As Mr. Marler talked about, the weather event along the coast was not particularly unusual. It was not in excess of a one-in-ten type of weather event. However, as you moved away from the coast the event was much more significant.

And just before I leave this chart I just want to highlight a couple of areas. This little circle down here in terms of the outages, that's Bakersfield; this is Fresno; and this is well, the Greater Bay Area here; this is San Jose; and the Livermore/San Ramon Valley.

This is just an expansion of the same graph focusing really on the Bay Area. Again, as I mentioned, the contour lines really in this area here, we really didn't see much in the way of outages, because it wasn't a particularly unusual event.

Where we saw the outages were really concentrated in this area here; this is kind of south San Jose; and the Livermore/San Ramon Valley. Again, they correlate very closely with the unusual nature of the weather event.

And of particular significance was the duration of this event, as well as the high minimum temperatures, the nighttime temperatures.

In terms of leading to transformer outages, there were really two major factors that we take a look at. The first is peak demand, and how customers responded, the load factor. And then the second is ambient conditions.

During this period in essence our transformers had no opportunity to cool down. The ambient temperatures did not drop down to normal levels at nighttime. And the other probably even worse impact was the customer response. I mean basically customers continued to operate their air conditioning equipment 24 hours a day. And I think the fellow from LADWP mentioned it, the diversity was gone. We didn't see that in terms of the impact on our equipment.

Just kind of a high level. It was mentioned a little bit earlier the number of people that PG&E employed to respond to this issue. We have 1000 construction and engineering employees really located in that San Jose and Livermore Valley areas we pulled in from throughout our system.

We responded to over 13,000 individual locations requiring investigation. This went anywhere from customer breaker trip and they want PG&E to come take a look at it, to restoring feeder outages and so on.

From a high-level system perspective, it was pretty minimal on our substation, in terms of our substation equipment, we really had three equipment-related, or six equipment-related outages affecting 21,000 customers. Considering we have almost 2000 substation transformer banks, we felt pretty good about that. That was a pretty good event from our perspective.

And on the transmission system we had a few -- outages, the largest driven by lighting strikes along the foothills. However, we did have three transmission outages that resulted in sustained outages to customers affecting about 10,000 customers.

The biggest issue for us was distribution transformers. Over this period we replaced about 1400 distribution transformers. Other transformers actually tripped and were able to be restored to service without having to be replaced. We're continuing to go back and look at those transformers to see whether we ought to be replacing those and addressing those going forward.

There's a little piece of information that I want to share with everybody here and in the audience, if I got the opportunity to do that.

I want to emphasize this point. There were a couple of media folks that picked up on, or made some, connected the dots between what was happening with respect to distribution system outages and aging infrastructure.

As it relates to our situation there was no connection. Looking at the transformers in particular, we looked at 80 of the transformers that failed. We saw a very equal distribution. Essentially over the, you know, in the ten-year gauge periods, you know, zero to 10, 10 to 20 and so on. There was no correlation between age of transformers and whether they were going to fail.

In our view this was driven by the unusual weather conditions; the way the customers responded to that; and the ability of our equipment to cool down in between load cycles. Those were the major factors.

There were a couple of questions I wanted to cover that were laid out for the workshop just from our perspective. In terms of load forecasting as it relates to transmission planning, we use a one-in-five load forecast probability for planning our bulk system. The notion there is that there's more diversity, you look at more of a one-in-five type of event.

When we get down to the local system from a transmission perspective, as well, it's distribution. We're trying to plan for a one-in-ten type event. There's less diversity. And this is essentially the process that we've agreed to with the ISO through stakeholders. It's also generally accepted industry practice as it relates to distribution system planning if you look at a one-in-ten event.

And from a transmission planning perspective we rely very heavily on the CEC's load forecasts. Obviously there's a lot of discussion that goes into that. We're parties to that, but we use that extensively.

We've found, in the transmission planning process, as well as siting cases and so on, it's critical to have an independent load forecast. Parties that have issues with our transmission proposals or whatever, they just generally don't believe that PG&E is forecasting accurately and relying on an organization like the CEC to come up with that helps us greatly in addressing those issues. So the independence of that forecast is critical. And to the extent that we have an inaccurate forecast, our plan suffers.

In terms of the equipment capabilities I've touched on it a little bit. There's really two factors. The first is ambient conditions and customer behaviors for load factors. To the extent that those change, our equipment is impacted.

And then the last point, investment planning, investment balance. Clearly proactive replacement is always more efficient, costs less, easier to do, less impact on customers. However, the challenge is when do you actually do it. And do you build and do you replace equipment for the type of event that we experienced here in July. I think it's a significant question.

Just to give you an indication, the average price of replacing transformers on a proactive basis, whether it's overhead or underground, is about $5000 to $5500 each, including equipment. PG&E has almost a million distribution transformers. And that's just the distribution transformer component. Cables, overhead conductors, switches, I mean you name it, this is not a trivial issue in terms of what we need to be going forward with in terms of our investment.

That concludes my remarks, thanks.

ASSOCIATE MEMBER GEESMAN: Kevin, I had a question on your slide two. And that is whether or not you have assigned or attributed a megawatt total to your outage trend.

MR. DASSO: It was actually -- the next one. That's a -- I was just speaking with my peer here on the load forecasting and supply side. We haven't done that, although one of the challenges that we have is these were largely residential customers. It's very difficult for us to accurately forecast, you know, what is the peak kilowatts for a particular residential customer.

We think that that modeling is going to be greatly improved by the smart meter project that we're implementing here, so we'll get more data.

At the height of the event on Sunday we had about 140,000 to 145,000 customers out. We used to assume a kilowatt per customer. We're pretty sure that's not accurate any longer, particularly in these areas.

Somewhere on the order of 150 to 200 megawatts probably is not unreasonable. We need to do a little bit more looking at that.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER BYRON: Mr. Dasso, thank you for the great data; this is fantastic. And there's a lot of dots, I'm going to connect the dots here, too, a little bit.

The question I had was with regard to the distribution system. Although I'm sure the ISO wouldn't admit it, they secretly probably love it to see all these distribution failures.

(Laughter.)

PRESIDING MEMBER BYRON: And reducing the load on the transmission line. And you seem to be pretty flat with regard to age of equipment, so age degradation doesn't seem to be the driving factor. But, you know, if these transformers are in place for maybe ten years and then you see an event that you haven't seen like this for a while, it really begs the question how much of this is increased load that's on that distribution feeder. And do you have any sense, have you got any feeling as to how much -- I think there's a couple other things that I listed here that it could be. Increased load on the feeder; you addressed the aging; of course, maintenance could always be a question or concern with regard to that; and temperature, obviously is creating a higher load.

But if you take out the temperature effect, how much of it is -- and particularly in those concentrated areas like in the south Bay where it's all dots, how much of that is increased load on individual feeders?

MR. DASSO: Interestingly we have a transformer monitoring system that we use. It takes the information that we get from our monthly kilowatt hour reads and converts that to a demand. And then compares that to the capacity of the transformers.

By and large the transformers that fail were not identified as being overloaded. So we're not sure that it was really a load issue. Again, we're doing some more investigation into it.

But these are areas, where the dots are, these are areas that will be -- where we consider kind of boundary issues, boundary areas. Areas that typically will see very high daytime temperatures, however they cool off substantially at night.

So, I think, you know, what -- our conclusion is that this was really a load factor issue. The actual load factors based on customer responses were much higher than what we had designed for, and what we typically would see in these kinds of areas.

And then to a lesser extent, but a significant extent, the ambient temperatures really didn't allow the equipment to cool down.

This is an issue that we're actually working actively with the Public Utilities Commission on to take a look at whether we ought to be looking differently at the transformers. It's our view that particularly these boundary areas we should be taking a little different look at in terms of how we size these transformers. Particularly if this is an event that may occur more frequently than this.

PRESIDING MEMBER BYRON: And if I may, I thought I read somewhere, as well, that you're replacing equipment with higher capacities, is that correct?

MR. DASSO: Generally when we go back in and replace it, we're putting in the next larger size up. Or potentially even larger, depending on what the survey indicates.

PRESIDING MEMBER BYRON: Thank you for

all this information.

MR. GIBBS: Great, thanks again. While we're in northern California perhaps Junona can talk a little bit about Silicon Valley and your experience.

MS. JONAS: Thank you. Thank you very much, Commissioners, for inviting me to speak.

While I'm going to talk specifically about Santa Clara's experience, I represent the northern California muni community, and much of our experience was very similar to the rest of the munis.

We are, Santa Clara Silicon Valley Power is about 1 percent of California's load. So we like to think of ourselves as the smallest of the large munis, but we're actually probably the largest of the small.

Our load is growing significantly. We have seen in the last year about a 10 percent increase in our load. So we had to temper that with our experience during this heat storm.

During the July heat storm our highest peak was 486 megawatts, and that occurred on Tuesday, July 25th. And that's 20 percent higher than that day previous year in 2005, and 17 percent higher than the highest load we experienced in 2005, which was in August. So significant growth there.

And actually, Monday should have been our highest peak, about 491 megawatts, but we had one of our customers that we were able to curtail 8 megawatts on Monday. So our high load was Tuesday.

During the height of the heat storm which we say is between Friday the 21st and Tuesday the 25th, we had 18 power outages. These were all residential, and none of our substations were affected; none of our industrial customers were affected.

Our load is unusual in the sense that only 10 percent of our load is residential customers; 90 percent is industrial.

So given the fact that we had 18 outages which affected 271 customers, this was a very small part of our total load, less than one-half of 1 percent of our load was affected by these outages.

The average outage was four hours; and the longest outage which affected ten customers, was 12.6 hours. And part of the reason why this is so is that we are extremely conservative in the way that we design our system. Our customers demand it. We are in the heart of Silicon Valley, high tech customers.

So we have a tremendous amount of redundancy in our system and our transformers are sized very very conservatively. We have a philosophy of switch to restore, rather than repair to restore, so that we are able to reroute our energy flow, or our energy service while restoration is being undertaken. So our customers do not have to be out the entire time of the repair.

On the generation side our power plants responded very very well during this time. We have a brand new power plant that went into operation last year Don von Raesfeld. And it is only a year old and it did very well. It ran the entire time.

Gianera Power Plant, which is also located within the city limits, ran the entire time. That is an older plant, about 50 megawatts. It provided our customers, both those plants provided about 36 percent of our customer need during the heat storm.

And in addition, we were able to assist our neighboring communities by providing 50 megawatt hours on Saturday to the grid, and 100 megawatt hours Monday and Tuesday to the grid.

So this is a great example of the type of reliability and flexibility that one can get with locally located power plants, not only for the community in which they're located, but also the surrounding communities.

In addition during this period we provided PG&E with mutual aid. We sent seven vehicles; we sent 22 transformers; and ten employees to work in the San Jose and Gilroy area to help restore power to those areas.

As far as our other northern California munis, Alameda experienced no outages during this time. And when we called Redding to find out what happened there, they said, "heat storm? what heat storm?" So I think that's probably pretty typical for them.

And that concludes my presentation. Thank you very much.

ASSOCIATE MEMBER GEESMAN: Junona, do you have a different standard for transformers that are in residential areas from those that are in commercial areas?

MS. JONAS: Not really, but we do have some older transformers in the residential areas. And those that failed were the older ones.

MR. GIBBS: Is there a cost analysis that's the basis for the increased sizing of transformers that you feel the additional upfront cost for the larger sizes more than pay back by avoiding future repair?

MS. JONAS: We did do the analysis as we started to build up our system. And it was based not so much on the cost as the type of customer that was moving into our service territory. We have a large number of high tech customers; Intel has their corporate headquarters.

So it was driven, obviously there is a cost element, but it was driven by the type of redundancy that we felt those customers really required.

MR. GIBBS: Thank you. Any other questions?

PRESIDING MEMBER BYRON: No, I just wanted to thank you for being here on such short notice today.

MS. JONAS: Sure. Thank you.

MR. GIBBS: Thank you. Well, let's perhaps move down south in the state if we could, and hear from a representative from SCE, Gary Schoonyan.

MR. SCHOONYAN: Thank you. Gary Schoonyan, Southern California Edison. I'm going to basically go through three things. I'll give you a real brief overview of how we responded to the distribution outages and what-have-you.

I will attempt to respond to the questions that were outlined. And then follow it up with a couple of closing comments and response to a couple of things that have already been said.

With regards to the heat storm from a distribution perspective, we lost 1375 transformers during the 14-day period. To give you some context of that, we typically replace about 12,000 transformers a year. So it represented a sizeable amount during that two-week period than what we replace in a given year.

As a result of our infrastructure replacement program that we were going through, transformer spares was not a concern. We presently have over 10,000 spares in inventory right now, should another incident of this nature occur.

The majority of the outages on our system were of short duration. We did have some longer term outages, approaching 72 hours. But I want to add that those longer duration outages weren't a result of transformer failures. We had numerous lightning strikes within our service territory, a number of downed powerlines, I believe on the order of 140. And it was these types of incidences that basically resulted in the longer duration outages that we saw.

At no given time, even though we had a total of about 1.2 million customers that had some level of interruption, at no one point in time were more than 29,000 customers without power. As mentioned before, these were predominately residential consumers. And my quick back-of-the-envelope, that works out to about 100, 150 megawatts, at maximum, that was probably unavailable or not being served at any one point in time.

In going through the questions, themselves, I'll just talk rather than read the questions, and hopefully address them all. As was mentioned, the power plants performed very very well. We only had two incidences where we had partial outages of power plants, which is very good, given the duration of the heat storm.

At no time were the so-called LD contracts caused any problems. They fully delivered the power. And it was brought up, I believe Jim brought it up, with regards to the price incentives and the financial penalties associated with not delivering the power that exists today that didn't exist some time ago when we were having the significant amount of generation that was unavailable. And as a result of that very high level of generator availability.

That, coupled with the fact that just the generators, themselves, I'm sure saw the situation and did everything they could to maintain the units and working with the ISO as far as scheduling the outages when they had to come down to repair minor things.

As far as the forecasting, there's been quite a bit of time spent on that. I think Art talked a little bit about that. As far as our short-term forecasts, I don't think that any given weekday we were more than 500 megawatts off on the shorter term forecast, which is within less than 3 percent of our system.

So for the most part, that was pretty accurate. When you talk about one- or two-degree differences in temperature, I think the chap from L.A. talked about the megawatts per degree, and I'm not going to go into the details of that, but in essence you can miss the temperature by three degrees and significantly encompass that 500 megawatt. So it's as much a result of temperature forecasting as the load forecasting effort.

Imports did play a very important role. Approximately at the peak time, roughly about 20 percent of our power was being imported into the service territory. And the transmission system, as Jim indicated, performed very very well.

As you're all aware, we're building additional transmission to help add another 1200 megawatts which hopefully is scheduled to be in service. This is DPV-II, December of '09. That would add another 1200 megawatts.

As far as the interruptible and demand response programs, they performed very very well. I think what's happened, there was a problem with particularly the interruptible program during the crisis period. It was primarily a problem of having people signed up for that program that really didn't belong on that program. And they didn't perform.

The folk that are on the program now fully understand it. Many of them have been involved in that program since we invented it in 1974 and have really good experience and know what to do, what not to do, and hence their performance is indicative of that.

And I look forward frankly to not only the price elasticity, which we don't really have a handle on yet, but Art alluded to, but I look forward also to demand response going forward, particularly with regards to the AMI approach that we're taking, and hopefully the ability to provide customers with easy ways to conveniently reduce load when system conditions and prices require such.

There's talking about the 15, 17 percent reserve margin. From our perspective, that's adequate for all planning purposes going forward. I think when we experience the types of situations that we experienced during this heat storm, and we can talk about, yeah, we were lucky here, and this worked right, but in essence things perform very well. There were the reserves there to handle even this very extreme type of incident.

Some even, earlier today, talked about a one-in-50. In fact, I looked at the chart that the ISO put up -- well, they didn't put it up, he didn't talk to it, but it shows basically the very extreme end of that particular curve there. And yet we served all the load.

So I think that the 15 to 17 percent that the Commission has embraced, as far as resource adequacy, is more than adequate. Furthermore, I think they're also going to be looking at multiyear, or at least investigating it, multiyear types of resource adequacy, which should further enhance that and provide more incentive for long-term contracting of new generation.

As far as the implications of the longer periods of humid weather and the higher temperatures, first of all, the jury's still out whether there'll be higher temperatures going forward or not. We basically anticipate that we're on a trend that will probably see some of that.

However, in saying that, even with the

global warming concerns, at least from our perspective those will tend to increase temperatures during nonpeak load periods. It'll affect, the higher temperatures will occur more during the non-higher temperature periods that exist today. So that you'll have higher use throughout the year, but as far as -- the jury's still out whether or not that will adversely alter the peak load temperatures that we're seeing during the summertime.

With regards to the humidity, other than the fact, and I believe some of that come into our load forecast, and there is some consideration for that, from an operational perspective and a transmission design perspective, with the higher forecasts obviously you'll alter your design of your system to the extent that that does materialize.

I think the biggest concern that's affecting the transmission design now is the higher usage per customer, particularly on the residential end. And whether that's driven by a/c cycling or other electronics equipments and what-have-you, remains to be seen. But there has been a noticeable increase in the usage per customer over the last two or three years that we have seen.

As far as the humid weather is concerned on operations on the distribution system, and this hasn't been confirmed yet, but I'm going back and relying on some experience when I was doing operations, is it may have some impact on things like flashovers and things like that associated with the distribution lines where you'd have to wash insulators more frequently. But likely will not alter the performance of the transformers, themselves, if they're adequately sized.

That gets to equipment capabilities and operations. I think the one other thing that I wanted to bring up is with warmer weather comes a higher likelihood of wildland fires, which I think are a huge concern from an operational perspective going forward. And the sporadic and uncertain nature of that just adds to the concern.

And the final, with regards to investments, as I'd mentioned, we're on a very aggressive infrastructure replacement program. Over the next five years we will be spending over $7 billion on our distribution system, and another $2.5 billion on our transmission system, upgrading it and adding new facilities.

And in closing, then, I did want to respond to a couple of things that were said. And I didn't want to leave the Committee with the impression that generators didn't have the opportunity, or existing generators that were going to repower did not have the opportunity to participate in our long-term procurement. They can.

Make a bid if they want to repower a facility and what-have-you. And if they choose not to do that, they're more than frequent shorter term. When I say shorter term, it's five years or less procurement efforts that the company has done. We have gone through 12 of those already.

So I didn't want to leave the Committee with the impression that existing generators are left out there in the cold without any options at this point in time, to either secure a longer term, albeit not a ten-year, a five-year agreement for the existing power, or a longer term agreement to facilitate a repowering of the facility.

And with regards to repowering, I want to also indicate that I think it was last year there was a particular piece of legislation that went through that provided greater certainty of getting through the process for those generators that want to go through a cost-of-service type of an arrangement associated with their contract, as opposed to a market-based arrangement. So there's things, tools in place for them to go forward on it.

Thank you.

MR. GIBBS: Great, thank you. Any questions? Great. I saw Randy sort of nodding during your presentation there. Perhaps we can hear from Randy Howard from Los Angeles.

MR. HOWARD: Thank you, Commissioners, and good afternoon. I'm not going to repeat some of the same things that others have said as to conclusions, but I'll try to be specific to LADWP and some of the impacts to us.

From a higher level perspective, we were just preparing to complete a ten-year integrated resource plan. It's been a draft; it's been out 90 days or so. We were just getting ready to issue that when we had the heat storm.

And when we looked back at some of our conclusions that we had derived based on the forecasting, and you've heard from my forecaster, I'm now four to five years further into that than I thought I would be. So I have to now move much further ahead in our planning cycle. And I lose four to five years of capital investments that I would have otherwise had to get me there.

So, from a planning perspective, at least for us, we have quite a challenge to now take these new numbers. Because, as Mr. Cockayne indicated, we thought we had this saturation figured out. That 6000 megawatts was about all they could use. And that there was diversity within that.

And we certainly realize that wasn't the case. And had we not had some outages that were going on, had it not been a very warm weekend and having a lot of customers look at reducing their load, what would have that eventual number been.

So we are challenged right now, relooking at that integrated resource plan for the next ten years; looking at a new revised forecast; and determining how we're going to meet those needs for the next ten years.

So I hadn't heard that previously, but I am concerned because I lost four or five years of capital investments that I would have otherwise had to help me get there.

From a system, it was a distribution problem for us, as well. It was never a generation problem. We were a net seller most of the time; we sold all excess generation that we had into the market.

It was -- our transmission operated very well. It was never a transmission issue. And that was a lot of very good planning and preparation. As mentioned by Southern California Edison, we continue to always worry on fires. We were very fortunate that there were no active fires going on and vegetation management remains a big concern to us.

As to our distribution system, we had no receiving station outages. We had no outages on our 3200 industrial stations. We had no 34-5 kV outages. Our outages were all related to residential customers. About two-thirds of our load is commercial; about a third are residential.

We had 79,000 customers that were impacted by outages at one time or another during the heat storm. One of our challenges was the hottest day, it was Saturday. We did not have sufficient crews to cover that unexpected event.

It was 119 degrees in Woodland Hills that day. It was something that no one had even contemplated.

The transformer failures that we did have, which was the bulk of our impact, and the most challenging for us to replace, occurred according to the heat. We watched the temperature, you watched the transformer failures.

So we got behind the curve in those reparations. And it took us until Monday, Tuesday to get a handle on the outages that occurred over the weekend and catch up and get everybody restored.

A little different for us, the transformer failures were primarily in the 20- to 30-year category, probably a little closer related to age of transformer use.

The other difficulty we had different than what happened to my fellow muni, was we did not have circuits that we could switch our customers to. The difficulty for us where every circuit was impacted. We had ten distributing stations that exceeded their ratings, but worked without outages. And the challenge on those circuits were, we weren't about to shift a customer over while we were doing the repairs, only to possibly cause an additional problem on another circuit.

So, some of the changes for us that we have to look at are really how we model the diversity of the residential load. We do not have a cycling program for air conditioners. We will have one very soon.

Because what we found is we did not have the diversity in the residential load that we had modeled previously in our distribution planning. Therefore, we need to insure that we can control some of that.

Had we had a very strong a/c cycling program, we probably would have reduced a number of the failures that we saw in these residential communities. We will focus a bit more of our energy efficiency dollars in some of these areas, as well, while we work on some of the planning to boost the system.

The other challenge we had was initially our field crews were replacing transformers with transformers of similar size, only to watch that transformer fail within several hours; and then have to go back and replace that transformer. So we did initiate a program to just upgrade those transformers as we were making the replacements.

We do have to go back and take care of some of the upstream circuity to insure that the system will remain reliable.

But, again, it was not a transmission or generation issue, it was entirely a distribution. And we are focused on relooking at how we do our distribution planning with less diversity now, and also the higher temperatures and humidity that we had not seen previously.

ASSOCIATE MEMBER GEESMAN: Randy, when you speak of diversity from a planning standpoint, are you looking for systemwide diversity, or locational diversity, as well?

MR. HOWARD: From a transmission generation perspective we look at systemwide. From a distribution planning perspective we look at very localized.

What we found is it was probably so hot that nobody chose to leave their home. What we also found is you could have turned your thermostat to 85 degrees on your a/c and it still would have never cycled off. It was on continuously.

And so we feel that most people in these areas because it was so hot, stayed inside, kept everything on, had their computer, had their big screen tv, and really did not reduce much at all. Whereas normally on a Saturday or a weekend you would have had people out shopping, taking care of errands, or otherwise. They probably chose not to do it that day.

ASSOCIATE MEMBER GEESMAN: Have you assigned some megawatt number to your distribution outages?

MR. HOWARD: Not as of yet, but that is something that we will be looking at.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. GIBBS: Great, thanks. We also have with us Robb Anderson from San Diego. Robb.

MR. ANDERSON: Just a couple comments. I'm not sure whether you'll be listening to me or your stomach at this point in time.

Just to highlight just -- I don't want to say this was a distribution event. I think it was an entire system event. It's a good chance for us to look back at everything in our system.

How well did we prepare from the generation side, the transmission side, the distribution side, the customer response side.

We're not finding, and there won't be any one silver bullet that we're going to see out of this process. But I think we'll learn something as we look into each one of those.

Just to highlight a little bit, since everyone else is throwing the numbers out, we had about 170 transformer outages in our system over this time. Much like PG&E, we found transformers that were two months old that went out, and we found transformers that were 50 years old that went out. It was distributed almost equally across the age group. So it isn't one particular age group of transformers that the issue was. It probably was strictly, you know, diversity of load that just did not occur on those kind of days.

We were able to get most of the customers restored rather quickly, almost all of our customers on the primary level that got knocked out. We had 99 percent of them back within 12 hours, and close to 70 percent of them back within three hours. So, most customers we were able to get back rather quickly.

The one item I'd like to just highlight on, and it's a comment Jim Detmers said, that we got through this summer because the investments paid off. And I think some of those were long-term investments, and some of those were short-term investments.

We've been investing quite a bit in our transmission infrastructure, you know; had Mission Miguel not been in by this summer, San Diego would have not gotten through this. We were able to get that project through.

And what I want to make sure is that as we look at these things, we look at what investments do we need to be making today so we can get through events like this in the future.

This is particularly an issue for San Diego. As most of you know, our entire service area is a load pocket. And although the generators, as a whole, performed well, over our peak the total amount of generation that was out in San Diego was a capacity amount greater than our G-1 continued C amount. So we do have load pocket issues that we think need to be looked at.

Just a random raising of reserve margins won't do much for a load pocket, unless that generation or the transmission can get that generation in the load pocket.

And as far as making new long-term commitments, SDG&E has made them in the past; got Palomar online. We're working hard to get the Calpine Otay Mesa plant online. We have before the Commission the Sunrise Power link, which will do a lot to solve our load pocket issue.

And we're also willing to make additional long-term commitments. The replacing of the older generation is going to be key for us. We've got a lot of the generation in the San Diego load pocket that is older.

What we're looking to do as part of that, the PUC's upcoming phase two of the long-term procurement plan proceeding, they want to do the last half of this year, is follow a long-term resource plan. Concurrent with that, go out with a long-term RFO so we can gather the data from all the bidders necessary, such that when we get our need finding out of that long-term resource plan proceeding, we can then very quickly act on contracts to fulfill that need.

So we look forward to working with all of you and hoping to make these things come around. Thank you.

PRESIDING MEMBER BYRON: I was going to

go with a general question, if I may, Michael.

You know, we've talked a lot about the supply side of this. Mr. Detmers, you sacrificed a few salmon, convinced the Department of Justice that you needed power. You also had some negawatts available to you, too. Would you describe for us, if you would, what you did there and why, and maybe some of the utilities might want to respond as to whether or not they agree with that approach, or if they might have preferred you do it differently.

MR. DETMERS: So that I can make sure that I'm answering the right question, Commissioner, as to the first, there was a lot of coordination that did happen. The coordination between all of the utilities and with the Northwest, and with entities outside that kept the imports at those high levels, most of that was in consultation and in coordination with the utilities, as well.

And so they were very much a part, be it Southern Cal Edison or San Diego or PG&E. All of that worked very very well. There were some things and arrangements directly with Bonneville and with those entities outside, as well as LADWP, that I worked directly with to make sure that we could accomplish both the transmission and the resource side.

PRESIDING MEMBER BYRON: I'm sorry, I didn't mean to put you in a defensive mode. I sacrificed the salmon, myself.

(Laughter.)

PRESIDING MEMBER BYRON: But I really you to address the negawatts you had available to you and what you did there.

MR. DETMERS: And that was the part that I wanted to ask you the question. When you refer to negawatts --

PRESIDING MEMBER BYRON: Well, you had an opportunity to call for interruptibles and/or a/c cycling. Would you explain what you did and why; and maybe the utilities might want to respond to what you did, and if they would have preferred you did it differently.

MR. DETMERS: Okay. When we actually walked through those hours, and I wanted to make sure that we mention some of what we refer to as the VLRP program, the voluntary load reduction program. We had several conference calls with the groups of customers that voluntarily shed load.

And the Department of General Services and the state is a part of that, as well.

So we achieved that reduction, but again, going through the peak hours to start to replay that so that you know what was happening in the ISO control room when we had to make the decision.

Sitting up at 50,000 megawatts on the overall power system, something that we were only projecting to go to 46,000 megawatts on that particular day on the longer term forecast, we had actually taken the system up to what I would refer to as probably five contingencies beyond what we had forecast, if I take every thousand megawatts over the forecasted level.

And so where we were operating was not a place that we had been to before; not had planned to before. And we were operating well beyond where we were, what we had projected and planned for.

In sitting there at 50,000 megawatts on the system and having declared a stage 2 emergency at that particular period in time, we made the decision not to call on any interruption of interruptibles right at the declaration of the stage 2 emergency, because there wasn't a need to.

We did have available reserves. We wanted to find out, and again we play things conservatively in the ISO's control room, to make sure that we would have the interruptibles again for the second day, the third day or however many days that we were going to be in this kind of condition. We had already experienced this since Friday.

We had no idea whether this was going to hold, the pattern was going to hold. And we wanted to make sure that we weren't calling on those customers unless we absolutely had to.

But when we declared the stage 2 emergency we actually watched about 300 megawatts of system response happen in the negawatt form. About 300 megawatts came off the system. And I have Mr. Rush sitting back here to correct me if I've got all these numbers incorrect.

But 300 megawatts immediately came off the system. What was that? I don't know exactly. That was the response of customers, both interruptible customers and other customers responding to our meters out on the system. What we refer to as the Macowatt meter. It's in relationship to Jim MacIntosh, our chief dispatcher. But it's the one that says things are critical; we need to have that response out there.

Some of it was those customers; some of it was interruptible customers coming off the system. But it was 300 megawatts is roughly what we saw come off. And then we waited.

During that time period between the declaration of the stage two and actually calling on the interruptible customers, these are the customers that roughly take 30 minutes to actually interrupt, we lost -- when we say we, and I'm saying it again, it was actually up in the Northwest -- a Hanford/Vantage line at the time. And actually went through a remedial action scheme event that backed off about 1500 megawatts of total generation on a RAS scheme.

When that was happening the system actually went into oscillation during that time period; and the system swing at that particular time was roughly 1000 megawatts.

We immediately interrupted the longer term interruptibles at that time. We still had enough reserves and spinning reserves to handle that, but our spinning reserves were right at 1500 megawatts. They weren't at the WECC standard of 5 and 7; they were actually sitting at about 1500 megawatts.

And we hit the interruptibles and pulled on the longer term. We did not use the a/c cycling. And that was something else that we did, because there was a faster response. We could hit that if we needed to in case something else came off the system. It's more dispatchable than the longer term interruptibles.

So we made the decision at the time to wait on the a/c cycling. As it turned out, as we started interrupting customers, the load actually began to turn. And people were taking it extremely serious at that point, customers, that is.

We saw the load just maintain itself there at 50,000, roughly, 200 megawatts. And it sustained itself. It wasn't saturation; it was actually response happening on the system. Once we get to that point we make those declarations, everybody's well aware of what's happening, and it's actually out on the tv cameras about that time.

We utilized that tv response, as well as other communication responses, to actually control that overall demand. We would have seen, most likely about 52,000 megawatts on the overall system if we would have just let it go. But, again, it was that overall response, a response to our requests, not threats.

And that's what we actually experienced. And that's how we called the shot when we did that.

But, again, we're looking at different response and the different programs, and what we can achieve and the other resources that we have available to us at that time to try to minimize any impact on customers as much as possible.

PRESIDING MEMBER BYRON: And I just wanted to open it up to the IOUs or the POUs, if they would have perhaps preferred to have seen -- preferred you to have used, maybe, the a/c cycling program that they have.

MR. SCHOONYAN: Gary Schoonyan. Fully supportive of what the ISO did. I mean personally I'm an ex-operator, and to the extent that you have --

MR. DETMERS: Thank you, Gary.

MR. SCHOONYAN: -- you know, ten-minute

lead-time stuff that you can call upon when you're as tight a situation as that, you try to hold onto that basically in case something else occurs.

And one other thing I wanted to just piggyback on it, I think the work that the ISO did with DWR, MWD and some of the major pump loads, there was also some scheduling of pumps there to basically reduce loads on those particular agencies.

And I think later on today Dr. House might be talking about things, other things that potentially could be done on the water pumping and the water systems that might be very beneficial.

PRESIDING MEMBER BYRON: If I could, I just wanted to ask one more question of Junona. Junona, you have kind of a unique program at Silicon Valley Power. I'm not sure if everybody's aware of it, in the way that you go after reducing load. Could you describe that a little bit? Maybe we could learn something from that.

MS. JONAS: We have a power reduction pool with our 20 largest industrial customers, and also the City, itself, where we -- it's a non-monetary agreement; in other words, they do not get paid for doing this.

But they are on call to reduce 10 percent of their noncritical load in exchange for not being turned off or blacked out.

And as I mentioned, we had one of our customers that we did ask to reduce their load the first day. But much like the ISO, we wanted to keep the others sort of in contingency that if we had the situation get worse, that we would be able to call on them. And we were able to handle it without having to call on the other customers.

But, it does work very very well. The customers certainly appreciate it because they know ahead of time that this may happen to them. They're able to reduce noncritical loads such as lighting, et cetera, within their buildings. And keep their critical load continuing to operate.

We did have them on-call. They did know this was a possibility. But we kept them apprised of where we were going, you know, fairly often actually. They were calling us.

MR. GIBBS: Okay, thank you very much. Knowing that I'm standing between you and lunch, are there other comments or observations from the Commissioners before we end this panel?

PRESIDING MEMBER BYRON: One last thing

if I may. Thank you, all, very much for coming. As you know, we have a customer panel after lunch, and I hope you're able to stay for some of that. But we appreciate very much your participation.

MR. GIBBS: Again, thank you, panel. We will reconvene at 1:30 after lunch. Thank you very much.

(Whereupon, at 12:31 p.m., the workshop was adjourned, to reconvene at 1:30 p.m., this same day.)

--o0o--

AFTERNOON SESSION

1:36 p.m.

MR. GIBBS: Continuing the workshop on the July 2006 heat storm. We had two excellent panels this morning; continuing this afternoon looking forward to two more and additional input from the audience here in the room.

Before we get started with panel number three, we'll provide an opportunity for the Commissioners to make a comment if they would like to do so.

Okay, great. The format here will be continuing with the same. What we'll first do is we'll go around the table here with the panel. I ask you to please introduce yourself and where you're from.

And then Loren Lutzenhiser will give us an overview presentation, and we'll continue with our discussion. Thank you.

MR. LUTZENHISER: Loren Lutzenhiser, Portland State University.

MR. McGUIRE: Wally McGuire, Director of the FlexYourPower campaign.

MR. GREEN: Andy Green, Energy Manager for Contra Costa County.

MS. TURNBULL: Jane Turnbull, energy consultant for the League of Women Voters of California.

MR. KREMESEC: Ken Kremesec, Water System Manager for Eldorado Irrigation District.

DR. HOUSE: Lon House; I'm the energy advisor to the Association of California Water Agencies.

MR. KINERT: Bob Kinert, Pacific Gas and Electric Company, account services.

MR. BOUSE: Earl Bouse, energy consultant to Hanson Permanente Cement in the San Francisco Bay Area.

PRESIDING MEMBER BYRON: You know, Michael, I just would like to add one thing. Customer panels are my favorite, so I want to thank you all very much for being here. I think what you all have to say is the most important thing we hear today, so thank you very much.

MR. GIBBS: All right, thank you very much. Loren, we'll go ahead and get started. The topic for this panel is customer response to extreme weather.

MR. LUTZENHISER: Thank you, Commissioners, for this opportunity. I wasn't here in the middle of the heat storm, but I was close by. And I actually did my graduate work at UC Davis, and so I always thought that I liked it when it was 104 degrees. And I do like it when it's 104 degrees in Portland for two days or three days or four days -- three, maybe. Four gets a little bit long and five is definitely too long.

So, at any rate, I've had some personal experience with this, and can only imagine what it must have been like in places here where it was 115.

I've had the opportunity to study human behavior and energy use over the last 15, 20 years or so. I was at UC Davis where I did my graduate work. And I've been fortunate enough to be able to work with the Commission and have some of my research supported by the Commission, to actually look at customer response under a variety of circumstances.

So, today what we're going to do, because nobody was studying what was going on this July; and in fact, there's virtually no literature on what happens, what do people do during, you know, hot weather events and so on.

What we can do is go back to the crisis

period 2000/2001 and the aftermath. Some research that I did then for the Commission; it's not an identical set of circumstances, but it's somewhat similar. Because at least it revealed some things about what people did during the crisis; perhaps why they did it; what they might do in the future. Although I think that's a little more sketchy at this point.

The data sources would include surveys in two waves that I did for the efficiency division here. As well as to look at some data from the residential statewide appliance saturation studies, the statewide pricing pilot, and there's some other behavior literatures probably that we're not going to spend much time on today, that is also relevant to this.

So the idea is that we're going to try to hit a few key insights that hopefully will help the conversation along a bit.

Surprising results of the crisis. I'm not sure what anybody did expect, but I think a lot of people feared that the, you know, sort of backlash to the Jimmy Carter kind of situation is what we would actually see, a lot of angry consumers.

Actually what happened was an unexpected consumer flexibility and a conservation response that was noted at the system level, as well as reported by consumers. It turned out that changes in behavior rather than efficiency improvements, software, people action rather than hardware, accounted for most of the energy savings. And a lot of that had to do with cooling, air conditioning and not using air conditioning; or using air conditioning sparingly.

Some of these changes actually persisted two years later when we looked at billing results and surveys. But sort of by the end of a couple of years they started to degrade, and essentially were not noticeable after some period of time passed. Not a mystery, I think. The crisis had passed and that's what sort of precipitated this.

In our work we ask people to report in their own words what they did, if anything, to conserve energy when called upon to do so. And they had a wide variety of responses that we looked at in a variety of ways. And we basically categorized them here, lumped them together into hardware and behavior.

Some people did a few things; some

people did a lot. The ones that we have circled are essentially air conditioning or cooling-related behaviors that were reported. And you can see that they're substantial in terms of the kind of things that people are mentioning, but there's an awful lot of other things that people were doing besides cooling.

What were they doing? The plea here, the request was to try to reduce peak demand. And some very clever advertising and direct messaging and news articles and so on asked for changes in peak behavior.

So, peak shifting, very little of it was actually reported by the people that we surveyed. Only a few small sort of subgroups that people talked about, sort of time-shifting some of these activities.

Cooling changes were much more frequently volunteered. Raising thermostat settings which was a suggested behavior on utility websites and a bit of sort of the public information that went out. Although I think there was some real caution in terms of asking people to make comfort sacrifices or what might be perceived to be comfort sacrifices at times. There wasn't a lot of advertising that promoted doing anything with cooling.

But the recommended thing would be to set your thermostat up a few degrees. Virtually nobody reported doing that. A lot of people, however, said that they just turned their air conditioning off all together, toughed it out, sucked it up is what they said in some cases.

Or used it very sparingly and in sort of a manual mode. They were overriding the automatic controls. This is something that we see in a variety of data sets as a fairly common behavior, and not simply something that's related to crisis conditions.

About a third of all of the central a/c owners said that they used little or no a/c during the crisis. And similar a number of room air conditioner owners.

Well, what were they motivated by? It's been surmised that this had a lot to do with cost. It must have been a price effect. We looked fairly closely at that, and most customers weren't exposed to direct price effects related to the crisis. Although there was a lot of concern about long-term costs; certainly costs to the system;

and possibly costs in the future.

So they were concerned about it enough they said, you know, to keep your electricity bill down is a reasonable kind of a motivation.

But also they had a variety of other motivations: to do your part; to try to help avoid blackouts; to use resources wisely; and so on and so forth.

So these were actually somewhat surprising. So, what it is that motivates customers is apparently a complex matter and it's not simply something that's driven simply by cost.

Will people conserve in the future? We came out of the crisis research both looking at residential consumers, as well as businesses, government agencies, and agricultural firms with this model. It's not rocket science, but it helps us to kind of understand what the situation is.

So, we say that it requires first a concern, an awareness that there's a problem and a willingness to act on it. You can be aware of it but not necessarily willing to act. You don't see it's your problem.

Once you have that, though, you have to have the knowledge and resources, the capacity to actually make some sort of change. Take some action, whether it's a behavioral change or whether it's a major investment, whether it's rescheduling your operations or whether it's buying a new piece of equipment.

You have to know where to go and you have to have the financial resources and the other resources to do it.

And finally the conditions of circumstances have to be right. You know, the fridge has to fit in the hole in the wall; it has to be the time to pull the ag pump out of the ground. It can't be right in the middle of the crop when it needs irrigation, so on and so forth. Market conditions can have an effect on this.

So we say that conservation action is really, in the long term, a combination of these sets of factors.

Okay, is conservation an acceptable request? Well, I think you have some direct evidence from this summer that, yeah, people did respond apparently, and in a positive way. This is some feedback from our surveys, and these are questions we posed to people. And these are really very very remarkable findings, I think.

And what's important here is that there's pretty good consistency across all these questions. There's consistency across two waves of surveys. And we just finished a third, or a separate survey of natural gas customers this winter; and we have very similar kinds of results that are coming from that.

It makes sense to ask citizens every once in awhile to reduce their energy use to avoid blackouts and so on. Agree, 93 percent. They don't think they're necessarily living in a third world country.

It's worth it to pay more in order to never be asked to conserve. How about buying insurance. Disagree, strongly. Real lifestyle changes are needed to solve our energy problems. This is quite surprising, actually. Now, we don't know whose lifestyles they're talking about, theirs or somebody else's, but nonetheless there's a general perception that something about the way we organize ourselves and use energy may need to be changed.

And then finally in reflecting back on conservation actions, you know, did it have a serious effect, were you, you know, sort of made less comfortable and so on; 77 percent here suggest that it either had no effect, that it was a serious or long-term one, or actually made their lives better in some fashion.

So, can you routinize crisis. This was a crisis. Can you make crisis routine. Well, I'm not sure. But the idea of the critical peak and critical peak pricing and critical peak calls, and these kinds of things, are a way to kind of make the crisis a routine part of everyday life.

This is a simple graph that comes from some of the work that Karen Herter and Pat McAuliffe and Art Rosenfeld have done, re-analyzing the statewide pricing pilot data that suggests -- and that study found that while the time-of-use rates were not necessarily producing significant savings, the critical peak rates certainly were.

And so what we can see here is -- and these are the critical peak customers behavior when the peak was called as compared to when the peak was not called. So you can see that there's definitely a conservation effect here, whether it's the high price, whether it's the fact there's an event that needs to be attended to, whether it's some combination of those. And I'll also point out that even at very high prices during a critical peak there's a lot of electricity being used here at the same time, at a very high price.

So, some of the work that we're doing now would be to say, well, okay, if we're really going to be serious about this, how would we want to do it. Are the best times to set a time-of-use rate, for example, the times that look best from the system's point of view. What about the times that might work best for the customers.

What's an optimal time length for a critical peak event. Can you get as much out of a short kind of a call as a really really long one. What kind of prices are considered fair and unfair. Some of the time-of-use experiments that have not done very well have been ones that I think didn't get the price differentials right.

So some of this is looking what the real costs of production and distribution are, but also what are the meaning of these costs, the perceived costs, to customers.

So, what price levels are they motivating? This whole business of manual versus program control. A lot of the policies that we might want to adopt or strategies might require program control. A lot of consumers override programs as a matter of course. Is that a bad thing; maybe it's a good thing. A lot of times their control patterns turn out to be quite conserving.

And finally, this is an interesting one, and we can talk about this, it's sort of now appearing -- does the emphasis on price or shifting from sort of a call for contributing to the general good to a price-driven system as a policy mechanism actually crowd out social and civic and altruistic responses.

And my colleague, Jamie Woods, an economist who looks at this stuff, was telling me about a couple of recent papers where there have been experience of this sort in other cases. This actually happens, where you sort of monetize something and then you try to go back and you actually don't get the original good behavior that you thought you were going to get. You got bad behavior in our monetized situation, and you get less good behavior after it's all over.

So, at any rate, there's a variety of

questions here that I think that we need to seriously pose if we're going to try to enlist the aid of consumers on the demand side. The comfort issue is a really interesting one. Comfort's a very complex thing. And I'm not going to go into it here, there are comfort models, some of you may understand these quite well.

But comfort is complex. It actually varies across individuals where people perceive themselves to be hot, is actually a distribution, it's not a single point. And it depends on what people are doing and how they're clothed and the circumstances and a variety of other things.

But we set these sort of magic points in here, you know, and so on and so forth, and there's a range of variation in human perception and reaction. What is -- your comfort standard one day may be somewhat elastic. And David Hungerford on the Commission Staff has a really nice dissertation that looks at this literature and starts to look at some of these kinds of questions.

So, there is some flex in it. But, you know, does that work up to 100 degrees, or 105, or at what point, you know, do you say, well, I can be flexible about my comfort, but it's hot. You know, everybody agrees on that.

And what happens after a number of days at very very high temperatures as far as this is concerned. We simply don't know. My suspicion is, having lived through one of these episodes and finding that Lowe's didn't have an air conditioner for my wife, the green family that has sworn never to have air conditioning, right, you know, is out looking for the air conditioner after six days. That, in fact, long spates of high temperatures do have an effect.

We also have to remember quickly here that customers are constrained in a variety of ways. Even in emergencies, about three-quarters of the people we talked to during the crisis knew of alerts, which means a quarter didn't at all. And less than half the people who knew about it acted in some fashion as the result of an alert. Now, they may have behaved in a conserving fashion overall, but in terms of responding directly to an alert of an event.

And also, you know, 90-plus percent of people at this point, based on a level of education, know there's such a thing as a peak, and peak energy, and a peak energy problem. But when you ask people to volunteer when the peak was, or we gave them some choices, actually. So we got 40 percent of the people identifying the peak at 10:00 in the morning and these kinds of things. Or flat saying, I don't know; I haven't the foggiest idea.

And at least a third, from our research, and this is borne out by our more recent research, never see power bills for a variety of reasons, and they never get a price signal, whether it's because of flat billing, or because of automatic pay or because one member of the family pays it and the other doesn't, or whatever. There's definitely an absence of price signaling going on there.

So, down to the last couple points here. First of all, if we want to try to better understand what's going on on the demand side, and some of this growth in load that we're talking about this morning, you have to realize that, of course, there's a lot of variability across households. It's fluctuating all the time, day and night. And it's quite diverse.

And this population, for example, this

is not unlike what this looks like in electricity plot for northern California where the mean is in here at about 6000 kilowatt hours; the range actually goes way out to 40,000, we just chopped it off here. The top quartile of the distribution actually consumes about 47 percent of the energy in the system.

So, it's a very different set of stories about what people are doing and how they're using energy at different points in this distribution. So averages are not that helpful. And even when we get down to some of the end-use estimates that we use in modeling like UECs, they can seem really substantial and solid. But they mask an awful lot of variability, and they're not that well estimated in many cases.

So, here's the last slide. And this, I think, follows up on some questions this morning, the weather stuff -- my plane got in late so I wasn't able to actually be there, but basically what this is, the blue bars are no air conditioners at all. Red is central air. Yellow is room air. These are the CEC forecast climate zones; instead of being numbered they're given descriptive names I think ACEEE came up with.

And then they're sorted just for the heck of it from low to high in terms of 50-year cooling degree days averages. So basically the coolest place is the Bay Area. And here in the south Valley is the hottest.

But this is the population of houses in each of those areas. And this is not expressed in actual numbers here. So you can get kind of an intuitive grasp of the scale and nature of the situation where there's an awful lot of places without air conditioning, for one thing. A lot of places that have a good mix of central and room air, which are different kinds of control options and policy options.

And, you know, some of these places on the coast, the south coast, the central coast -- the south coast here, the central coast, San Diego have a fair mix of a/c and non a/c in relatively temperate climates. It would be my strong suspicion that you're going to see load growth from new a/c adoption not just in new housing, but in retrofit. It's going to happen in these places because that's where there's room for it to happen, I think.

So, those are my remarks for right now.

MR. GIBBS: Thank you, Loren. Any questions? Loren, as you take your seat I thought I would just start with one question, which is the analysis of customer perspectives and the responses from 2000/2001, is that correct?

MR. LUTZENHISER: Yes.

MR. GIBBS: I guess my question would be, what can you say at this point recognizing it's early, but what can you say at this point about the applicability of those results and customers' willingness to respond to a different type of event, in this case this heat storm that we experienced?

MR. LUTZENHISER: Well, I mean I think the short story here is that, you know, people are willing to respond. Everybody is not. A substantial portion of the population probably is. There's probably widespread sentiments that would support conservation response even among people who are not going to run right out and do it necessarily. Who are not in a situation where they can.

It's not a crisis in the same sense, although I think this last summer came close to being one. But it wasn't the same kind of crisis, with a combination of factors. But I think that there's reason to believe, based on things like the response to critical peak pricing and other things, that people aren't of the mind that this is sort of a one-off.

It happened in 2001, so, okay, I'll never have to do that again. I think there are conditions under which there are deals that can be made with consumers, and conditions under which there would be a fairly substantial, but still marginal, conservation response from behavior from demand response kinds of things available. But with the caveat that not everywhere, not everybody, and in fact there's some opportunities, and I think some opportunities we realize, obviously, for load growth at the same time.

MR. GIBBS: Thank you, Loren. Any questions?

Loren, as you take your seat I thought I would just start with one question, which is the analysis of customer perspectives and the responses from 2000/2001, is that correct?

MR. LUTZENHISER: Yes.

MR. GIBBS: I guess my question would be, what can you say at this point recognizing it's early, but what can you say at this point about the applicability of those results and customers' willingness to respond to a different type of event, in this case this heat storm that we experienced?

MR. LUTZENHISER: Well, I mean I think the short story here is that, you know, people are willing to respond. Everybody is not. A substantial portion of the population probably is. There's probably widespread sentiments that would support conservation response even among people who are not going to run right out and do it necessarily, who are not in a situation where they can.

It's not a crisis in the same sense, although I think this last summer came close to being one. But it wasn't the same kind of crisis, with a combination of factors. But I think that there's reason to believe, based on things like the response to critical peak pricing and other things, that people aren't of the mind that this is sort of a one-off.

It happened in 2001, so, okay, I'll never have to do that again. I think there are conditions under which there are deals that can be made with consumers, and conditions under which there would be a fairly substantial, but still marginal, conservation response from behavior from demand response kinds of things available. But with the caveat that not everywhere, not everybody, and in fact there's some opportunities, and I think some opportunities we realize, obviously, for load growth at the same time.

MR. GIBBS: Great, thank you. I think that next it would be useful to hear from Wally McGuire from the FlexYourPower.

MR. McGUIRE: Well, thank you, Commissioners, for having me up here. Thought I would just start with one question, which is the analysis of customer perspectives and the responses from 2000/2001, is that correct?

MR. LUTZENHISER: Yes.

MR. GIBBS: I guess my question would be, what can you say at this point recognizing it's early, but what can you say at this point about the applicability of those results and customers' willingness to respond to a different type of event, in this case this heat storm that we experienced?

MR. LUTZENHISER: Well, I mean I think

the short story here is that, you know, people are willing to respond. Everybody is not. A substantial portion of the population probably is. There's probably widespread sentiments that would support conservation response even among people who are not going to run right out and do it necessarily, who are not in a situation where they can.

It's not a crisis in the same sense, although I think this last summer came close to being one. But it wasn't the same kind of crisis, with a combination of factors. But I think that there's reason to believe, based on things like the response to critical peak pricing and other things, that people aren't of the mind that this is sort of a one-off.

It happened in 2001, so, okay, I'll never have to do that again. I think there are conditions under which there are deals that can be made with consumers, and conditions under which there would be a fairly substantial, but still marginal, conservation response from behavior from demand response kinds of things available. But with the caveat that not everywhere, not everybody, and in fact there's some opportunities, and I think some opportunities we realize, obviously, for load growth at the same time.

MR. GIBBS: Great, thank you. I think that next it would be useful to hear from Wally McGuire from the FlexYourPower.

MR. McGUIRE: Well, thank you, Commissioners, for having me up here. I do want to mention one thing, based, Loren, on what you said. Actually in 2001 and '2 we did have a substantial amount of tv and radio on the cooling issue. In fact, the message, we've never promoted air conditioners at all, EnergyStar or otherwise. We say don't use your air conditioner, cool with fans or something like that, even to today. So I do want to say I think there was a little bit more than maybe you did.

In 2001 -- in a minute I'll get into why I think it is different. By the way, sure, what Loren has said, and his great work after the energy crisis, I mean it was very helpful in instructing us.

I think what 2001 proved, though, is that people realize that there are a few simple things you can do that make a big difference if we all do it together. I mean my biggest problem, our biggest, the state's biggest problem going into the energy crisis is we had some survey research that said that virtually 60 percent of the people thought it was hopeless. That we're into an energy crisis and there's nothing we can do about it.

They said they were conserving; over 90 percent said they were conserving and had enough information, but when you probe the data they didn't know what to do. They thought turning out the light was about the extent of it.

So, we entered into a situation; in fact, if you look at the term FlexYourPower, that was created to put the burden in a way over on the people, flex your power and you had the power to do it. In fact, if you look at our whole strategy it was to get everybody working together and get rid of all that anger that existed.

But I think 2001, at least from my perspective, was a hallmark. I think we made a change. I don't think you see those attitudes today. I think you find people much more of the belief that they can make a difference. I think we saw it even in the July time, when people were willing to respond.

There are some major differences, I will tell you. I'll get into those in a minute, which we could change if we really got in a pickle in 2001, coming up.

This morning was almost entirely on the supply side, and it was, I would say, a little bit more on the engineering and economic side of it. Ours is much more mushy, it's trying to convince people to take a behavioral change.

But I will say, and I think the reason for that is because you can count it. You can count how fast the needle's spinning when you're making electricity and miles of transmission lines. It's very hard to quantify, as Loren will tell you, how much is saved.

That doesn't mean it's not occurring. I would just say that sometimes I think we kind of gravitate towards those things we can count, whether it's a rebate or something like that. And we kind of discount, in a way that people are willing to take those behaviors.

In 2001, I'll give you the best example. One of the first meetings I went to was a meeting of business executives. And they -- talk about an angry group of people going into that summer.

They were looking at a report that said $16 billion in economic loss and all that.

And at that time I think the projected shortfall was 5000 megawatts, which is why everybody said, we're going to have blackouts. No one thought we could save that much.

With a couple of the utilities we put together some numbers that said if every business in the state just unscrewed every fourth light, delamped every fourth light, which would not cause a huge inconvenience, and turned HVAC up to 78, that's 5000 megawatts.

I think there was an attitude change. Say, wow, you mean it's that simple to make a change. And, in fact, that was our strategy for the whole, throughout the energy crisis, was to go out and tell people it's simple, it's not the Jimmy Carter -- you don't have to struggle with it.

So, this year, let me tell you a little bit about what we did going into this year and during the July period. I'm hoping most of you have seen our television advertising. Most of it is energy efficiency by definition, it's promoting the value of EnergyStar appliances, CFLs and whatnot.

That's different than the conservation demand response. But what we've done is we've concentrated all of our FlexYourPower campaign into this critical summer months. Doesn't help our efficiency campaign as much, because usually your appliance thing would be during appliance promotions and lighting would be in the fall.

We put all that money into the summer for one reason. We needed to lock in a fairly high media buy throughout the entire summer. And then when the ISO, which has been great to work with, by the way, when they give us those two- or three-day-out notices, we have the ability, with a partnership with all of the about 300 stations in the state to switch out our advertising toward demand response stuff or voluntary. So we pull efficiency off the air; we go into voluntary conservation.

We this year are doing something a little different. We were afraid of wearing people out, you know, that we keep calling on it. We didn't want week-in and week-out. So, what we do is we run some get-ready-for-hot-weather. We say when officials -- it's getting hot; officials could call a flex alert.

We tell them the three tips. By the way, that's 78 thermostat; turn off unnecessary lights; and use appliances and major stuff after 7:00. Those have been the three tips we've used really since 2001.

When an alert gets called the tv stations and radio's been very good to switch out. And we just actually interrupt our own ad. It's set, officials have called a flex alert, do these things right now.

And then when the alert goes away we run another couple days of ads thanking people. We say officials have canceled the alert thanks to the actions of millions of people who did these three things. We want to close the loop with people. And then we go back to our efficiency advertising.

We ran about ten days of those ads. I mean that shows you the extent of the storm. We did not plan that. We thought we'd have generally a five- or six-day period.

We also worked with the press, weather people, news people, did press conferences and whatnot. That's the first thing we do. The flex alert network is primarily tv, radio and news media.

The second thing we do is we've built over the years what we call a flex alert network. That's working with associations as BOMA, the Farm Bureau, others. And between switching out their web sites and email blasts when an alert comes, we hit about half a million, 500,000 businesses, and ask them to take voluntary actions. It's those simple actions; we really need it, folks; now is the time to do it.

And a new feature this year, which many of you, at least in California, saw, probably were the traffic signs. Due to great help from Sunne McPeak and the Governor's Office, we got the Caltrans folks to switch out traffic lights.

If I had one message, and I felt it strongly this morning, is that we need to give credit to people when they do conserve. I personally believe it makes a big difference. But, if we discount it, if we spend all of our time, I know this is a closed meeting, talking about the need for more generation or this or that, or paying for a demand response program, all of which are urgent, we marginalize the good behavior of people who are willing to take an action.

I mean our polling conforms with yours. We think the vast majority of people are willing to take an action. Unlike the energy crisis, about half of them, even though they know what to do and that it's important, they will not take the action unless they think it's imminent. It has to be much more urgent than what we're communicating right now.

In 2001 it was pretty clear, every news person said, blackouts are imminent. Once you say that people are willing to take an action. If we back down and we say it would be helpful, we lose about 50 percent of the folks.

And the reasons for doing that are clear. We don't want to keep people in a constant state of emergency. We just have to expect that the results will be a little bit lower.

This morning, I think it was the gentleman from SDG&E, was saying that the response was going back to the levels of 2001. If that's true, and I don't know that it's true, that's certainly not what I think SCE said, or what our experience was.

But if that's true, if the word respond is the critical one, in other words if they're responding, as the title of this session is, to hot temperature, they're going to respond by turning on the air conditioner.

What we're asking them to do is respond to save electricity. And that has to be communicated. I mean that is why I'm a strong advocate for an aggressive effort on the part of the Energy Commission and the PUC and our campaign and the utilities to let people know that this causes electricity crunches, and that we need to do something about it.

And then we have to tell them what to do; and ask them to do it. That's the only way to truly measure the response which is in your title. It's not a response to the hot weather; it's a response to the result of that hot weather, which is electricity use. And we have to be crystal clear when we communicate to the public that that's what it is.

Which sort of gets me down to why I think comparisons with 2001 are not totally accurate. Let me give you about five differences in the campaign that we put together back then to what we're doing now.

In 2001 the actions we asked people to take were for the entire summer. In other words, business leaders, it ended up being over 1000 major businesses signed a pledge to do those actions.

This is different. This year it's only when you hear an alert. In other words, it's a stop-and-start type of a communication. That's really hard to maintain. And we need to know that. For instance, if we went into a real problem next year, we would have to revisit the decision to do a start-again/stop-again alert system, and say this is a tough summer, folks; we just do it. Turn them out for the summer and let's go forward.

A second way where the comparison is not particularly accurate, the budget for the conservation side in 2001 was over ten times what it is now. It's a fairly small budget. Not making a pitch for more money, but just don't forget that we had a substantial amount of advertising money on, and the budget -- and that's only, that ten times is not adjusted for inflation. In other words, media budgets go up about 7 percent a year, which means we're in a declining budget for the last four or five years.

The third reason why it's way different in my judgment is that there was a genuine fear of blackouts, and for good reason, back in 2001. They don't, I don't believe, have that fear now. In fact, when we did our research to do our advertising for this year, very few people -- they all kind of think it could come back, and they're prepared for it, and they're prepared to take an action. But they don't think it's here now.

In fact, in advertising terms it's called a low intensity message. People just, they don't wake up in the morning thinking how do you save energy. You have to break through the noise level a little bit.

The fourth major difference, I saw a survey, I think it was by McKenzie, 67 percent of all Californians thought energy was the most important issue in their lives back in 2001. Now it's down probably in the single digits. Education and terrorism, there's other things that have replaced that.

When you run a social behavior campaign you have to get their attention, and that 67 figure made our job very easy. We have to capture their attention, which the heat, I think, did this time.

And then the final point was I don't believe we had the extreme weather that we had this last July. Somebody properly mentioned that even setting your thermostat at 78 doesn't necessarily mean the thing's going to go down. I think that the extreme weather was a little different than we had in 2001. At least I don't remember then.

Nevertheless, we have indications that during that July period of a few weeks ago, that a fairly substantial number of people did respond. We're out doing a little polling right now, and the numbers are anywhere low numbers was what you reported back then, which is 40 percent, up to about 80 percent of the people who got the message, actually self-report that they do something.

So, in short, I just hope we continue to find ways to build the demand side into our energy reliability mix. I personally believe that people are very well educated, probably more in this state than any other place, because of the crisis we went through.

They're prepared to do it, and if we count on them a little bit, they will respond. But we have to thank them. As policymakers, we have to -- I keep badgering Jim Detmers about that, you know. Say, you've got to thank them. Don't just say we brought this power in and did that. You may have done all those things, but we have to continue to tell the people that their actions make a difference, or they're not going to take them. They'll turn that air conditioner on.

I think probably that's it. I guess I would say, just put myself in, again, Loren's camp, that I believe that social and altruistic motivations are, in many ways, I believe, more powerful than financial.

On the efficiency side I've been a long advocate that we should not use rebates solely as a way to buy energy efficiency, because I think it's sort of it builds in an expectation, and I think we found that a great number of people will respond to doing the right thing and saving money. Remember, if you save electricity you save money. That exists all the time.

So, I think people respond. I don't

know, I think the press conferences we had during that crisis, the ISO was saying about 1500 megawatts came down, or, Jim, I think you said 52 is what we predicted. I think mid-morning it ended up 50.

I, for one, would like to believe that the people of the state responded. That they know how to do it. They'll do it if we ask them.

MR. GIBBS: Thank you very much. Questions?

ASSOCIATE MEMBER GEESMAN: Wally, in terms of the budget, my sense is the 2001 program was really, if not a year-round, at least a seasonal program; whereas this past year it's been much more of a peak advertising. I think you said you advertised for, was it ten days?

MR. McGUIRE: Well, you're right, John, in 2001 and 2002, it was a 12 month that year. We had a budget that took us throughout, and it was a fairly substantial buy.

ASSOCIATE MEMBER GEESMAN: How would, if I looked at the ten days that you were up this year, how would it compare in terms of the level of intensity with any given ten days in 2001?

MR. McGUIRE: Because we put all of our

efficiency money into the summer, and buy at the point level, if that's what you're asking, on tv and radio, it was equivalent to 2001. It's just that we have no advertising -- we went on in June; we had not been on the air for ten months, so the message probably declined a little bit.

So, there's, of course, a buildup. But the points per day is about the same as during the energy crisis.

ASSOCIATE MEMBER GEESMAN: When I came on the Commission in 2002 there was a great deal of thought given to trying to craft a message that would encourage people to invest in something that would have permanent efficiency impacts, as opposed to the more temporal behavior adjustments.

Your sense as to how this year really presented a different challenge?

MR. McGUIRE: No, I do believe, in fact most of what we do is the longer term efficiencies, investing in energy efficient products. I think that that is critical. And you can count on it, you know. At least if you can count it, you can count on it.

I have not been as big a fan to totally exclude conservation. I think that if you look at any social marketing campaign, or even social movement, if you go back to the civil rights movement, you have to challenge people to take an action on their own. You don't say, I'll help you buy something that will help you save money.

I think you have to do both. And I actually think the mix this year is pretty good, to be honest with you.

ASSOCIATE MEMBER GEESMAN: Our policy report last year suggested more of an emphasis in the utility-oriented efficiency programs toward peak savings, as opposed to energy savings.

Do you have a sense as to whether that's an appropriate direction in which to evolve?

MR. McGUIRE: I totally do. I mean I think if you're going to invest in making people more efficient, those kilowatts you're buying at peak hours are a lot more expensive. I mean it seems to me that that's where your energy ought to be put. I'm a total fan of that.

ASSOCIATE MEMBER GEESMAN: And although I'm not directly involved in this area, my sense is we must be at about the point in the planning cycle where we're beginning to review or formulate the next three years of utility efficiency investments.

MR. McGUIRE: We're actually --

ASSOCIATE MEMBER GEESMAN: -- involved in that?

MR. McGUIRE: Yeah. Well, we're actually into the first year of that. That has been done. The 2006, '7 and '8 programs are funded. And the PUC's done a great job, I will tell you. First off, they've given longer planning cycles, which was absolutely critical in advertising or working with manufacturers or -- you need to have a couple-year cycle and flexibility.

And I think they've approved a great increase in efficiency money with the procurement proceedings.

So we're in the first year now of a three-year, kind of golden age as far as I can see; there's a lot of money, and I think it's well spent.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. GIBBS: Great. Again, thank you very much. Well, we do have representatives from customers here at the table, so why don't we hear directly from them. And perhaps we can ask Jane

Turnbull to make a few remarks.

MS. TURNBULL: Thank you, Michael. I don't have any statistics. I represent the League of Women Voters. And while there are 11,000 members of the League around the state, you know, we haven't done a survey of 11,000.

However, I can report that over the last several years the Leagues in the state have studied the energy situation intensely with the purpose of revising our energy policy positions. Because we cannot speak to an issue unless we have a position that has been studied.

So, therefore, most of the 70 Leagues around the state have had an energy kit that they study from, and they answered consensus questions and gained a general understanding of the electricity system in the state.

A lot of the focus was on reliability, coming out of the 2000/2001 period. And I think most League members now have an understanding of what peak power situations look like. And the interrelationship between cost and peaking needs. That, at least, was our objective, and I think we had some really good graphics from the Energy Commission in the energy kit, and everybody now knows how the peaks go up.

Most League members now, I think, do their laundry and dishes after 7:00 at night routinely. But perhaps that's not going to, you know, be a solution when the time comes for a heat storm.

One of the areas that the League has endorsed very strongly is the use of smart meters. We do think that the price signal is significant, not necessarily because of the cost, per se, but because the pricing signal indicates what's happening to the whole system. And the demand upon much more extensive power.

And, in general, the League feels that these are personal lifestyle decisions that people are making, and they have to be responsible for the decisions that they are making.

One of our concerns, though, is the remodeling of new homes. We do think that the Title 24 standards are great. But are they sufficient when a, you know, 1800 square foot home is being replaced by a 3600 square foot home. The energy requirements that go with those are really very significant, and virtually all of them are going to have central air conditioning in the future, whereas most of them, you know, many of them will not have air conditioning going into a remodel.

So, I think one of the things that the League is supporting are efforts to get local communities to think green. To just get an understanding of what the potential is if, for instance, the requirement for large homes becomes Title 24 plus 15 percent. And there are communities that are starting to think about that.

ASSOCIATE MEMBER GEESMAN: The City of Mill Valley, I think one of those towns down where you live, may have been Saratoga, has set their energy budget, I believe, at the assumption that it would be sufficient under Title 24 to serve a 3500 square foot home. And any load above that would be expected to be met by solar systems.

The City of Aspen, Colorado has done a similar ordinance. They draw the line at 5000 square feet.

MS. TURNBULL: Right. And Los Altos Hills, you know, draws the line at 6000, which is not --

(Laughter.)

MS. TURNBULL: -- necessarily very --

ASSOCIATE MEMBER GEESMAN: Yeah.

MS. TURNBULL: But nevertheless, you know, a few good examples might go a long way in at least getting people to think about it.

Actually last night I met with the environmental committee in Los Altos, and we started talking about what we can do to make Los Altos a greener community. And Los Altos is going to, you know, be pretty reluctant, I think, to move in that direction. But that's a pretty strong committee, so maybe we will get something to happen.

A couple other anecdotes that I would like to point out, have to do with the fact that one of the days of the heat storm my husband and I were driving north on I-5, and I had car troubles in Red Bluff. So we had to pull off in Red Bluff and leave the car for a period of time there, and walk the streets of Red Bluff.

Red Bluff doesn't have trees. And I have never in my life wished for trees more. I mean I think there are communities where there are opportunities to think in a different sense. The baking of the heat from those, on the sides of those buildings was just dreadful.

And then we went in to get a Coke in a restaurant where the temperature had to be 65 degrees. So, obviously some of the messages are not getting through to people.

My major point, though, has to do with this discussion on price versus altruistic behavior. And I do think that altruistic behavior is an enormous motivator, but people have to know when to be altruistic. So I think the price signal, itself, becomes the means by which they know that they have a problem.

Many people I know did turn their air conditioner settings up to 78 and 80 degrees. But there are quite a few people I know who didn't. And those who didn't really don't have an understanding of the system, itself, and what the needs are behind the light switch.

MR. GIBBS: Okay, well, thank you very much.

PRESIDING MEMBER BYRON: If I may, Jane. Those of you who don't know Ms. Turnbull; she's worked in the electric power industry I think most of her career; so she's kind of in a stealthy role here as the League of Women Voters.

Jane, my question is sort of general,

and you can answer it in any one of a number of ways. What I'm trying to get at, though, is the same thing that you brought up a second ago, about the altruistic versus the economic motivation.

You kind of addressed that, but by Monday, what do you think? Don't you think residential customers were tired of turning off the a/c, or turning up the thermostat. And said, enough of this, I need my a/c.

I mean you'd indicated many customers didn't respond.

MS. TURNBULL: Um-hum, I think people have a sense of the normal daily patterns, and they're more likely to conserve between the hours of noon and 7:00. But at 7:00, then they're going to turn the air conditioner up or on.

And so I think even after three days they may be pretty good during what they consider to be the peak power times, but, you know, when it starts to get dark, even if the temperature is up, they're going to, you know, want their air conditioner on.

But my sample is such that I really, you know, no statistics.

PRESIDING MEMBER BYRON: Sure. Yeah,

how come you didn't come with any data?

(Laughter.)

PRESIDING MEMBER BYRON: I'm just kidding, of course. You don't have access to that kind of -- thank you.

MR. GIBBS: Great, thank you very much. And, of course, one of the largest loads on the system overall is for water systems, and energy for water pumping, and Lon House is here to talk a little bit about water systems and how the water systems deal with and are affected by extreme weather.

DR. HOUSE: Good afternoon; I'm going to just give a brief presentation on the response of the water utilities in the state. And show what we did, some examples of what was done during the peak period. And respond to some of the questions the Committee put together.

The first thing is that if the water agencies are using alternative pumping schemes, which is primarily natural gas pumps, there isn't any inherent fatigue the further and further along you get in the heat storm. With one exception, and you'll see it in the presentation today, is as these alternative pumps are being called on and being used more and more, it does increase their failure rate.

For if the water agency is using existing storage for demand response, fatigue does occur after multiple days. And we have some good examples of that.

And then there's also the issue of evapotranspiration, and that's what, in the water community, is called how long it takes before your grass starts turning brown. If there are multiple days of heat, the normal watering cycle may not work, and the person will go out and say, oh, my grass is turning brown, and they'll start turning on their water, additional watering cycle. And that's one of the things that the water community was facing.

This is, start on the north coast, this is Humboldt Bay. And you can see, and I have a number of examples in my presentation on the peak day. And you'll see that they drop about 1200 kilowatts. But the one thing that you'll see, particularly on this day, is you'll see some of the residual, some of the sort of customer fatigue.

Because normally Humboldt will drop the

entire amount down here. But you'll notice it in this, and you'll see it when we talk about Eldorado, is they couldn't shut everything off for six hours on this day because their water demands were so high.

So what they did is they did drop it down; they dropped about 1200 kilowatts, down for about three hours, and then they dropped the whole thing for the remaining three hours.

Okay, this is Eastern Municipal. And this is the one I was telling you about. You notice that there's a substantial drop right here, but you notice that this guy, this account, that the previous one was for one account in Humboldt. This one is for three accounts in Eastern.

And what happened, if you'd looked at this the week before, you'd have seen everything drop off from noon to 6:00. But what happened is this pump here developed vibration on Friday. And so when Monday came along, they said, we're not going to shut it off because we're having problems, we're not going to shut off our electric pumps to switch to our natural gas pumps because that pump is having a problem and we've got to get it fixed before we do that again.

And so this is an instance -- and normally you will see the entire, approximately 4 megawatts, go out of the onpeak period. But this is a case where just the extended use of this particular alternative to electric pumps ended up causing a problem because it wasn't being used there.

All water agencies that supply treated water in the state have some kind of storage. But the storage has been added to the system to optimize the water system delivery. It's not to optimize, not for onpeak electrical generation.

And the reason for that is they're simply too expensive to put a storage facility in just for the onpeak electrical generation.

And within the storage facility there are basically three types of water that they have to keep in there at all times. One is fire protection water; and one is contingency water. And contingency, water utilities are very similar to electric utilities in that they -- in a lot of ways. And one of them is in this is contingency.

Whereas, in electric side we're used to the single largest contingency or the two largest contingencies, well, the water community does something very similar. And they say, if something catastrophic happens, one of our main lines breaks, how much water will we lose before we can shut that line off. So that we're going to have to keep that water in storage.

And then the last one is water for pressure. Because water, at elevation, provides pressure to the system. And this is just -- the maximum in the water community is a full tank is a happy tank. So these tanks are either going up or they're going down. They're not just sitting there at any time.

Okay, demand response fatigue with storage. It is somewhat dependent upon the system. So it's the amount of storage they have, water storage they have, relative to water delivery demands.

And the fatigue comes from two forces. One is evapotranspiration, which we talked about, is we end up with multiple days of very hot weather; pools end up evaporating and the lawn ends up drying out, and so the customers will end up with more water demand than we have.

But it's also the refill requirements and the minimum pool levels, which is what you're allowed to have in storage.

And what you'll see, you'll see some fairly interesting examples, at least I think they are, that the water agencies have these sort of operating rules. And they will drop down and they'll actually go into this minimum storage pool. And you'll see an example with Ken's system in which they went into that minimum storage pool, and it's okay if you do that if you can recover the next day. But when you can't recover the next day, at some point you can't keep going down into it, you can't sort of keep stealing water from this minimum pool. And that's what we saw, and this was one of the first times that we've seen that.

Okay, this is East Bay. And you can see, there's a couple things to notice here. One is -- and what we did here is this is the Mondays for that month. And one of the things that you notice, the red line here is the 24th, which was the end of the heat storm. One thing you notice is that they're pumping more water; they're delivering more water because this line here is the Monday the week before. And look what this red line here.

So what's happening is what you're seeing there is you're seeing the increased water demand that's occurring. And then you'll notice that what they do is they drop about 15 megawatts at noon. And normally they come back, they drop it from noon to 6:00, and then they come back.

But one of the things I wanted to talk about right here, and we've talked about altruism and things like that, you notice that what happened here is instead of popping everything back on when they normally did at 6:00, they brought it up like this. This was because of a call from PG&E. And PG&E called East Bay and they said, hey, guys, we don't want you throwing another 15 megawatts on our system at 6:00. Can you bring it on slowly, and give us a chance to recover from it.

And so that's what happened. You can see right here. And these are good corporate citizens. And you can see, instead of popping it back up here, they ended up bringing it on slowly, and refilling slowly.

This is a busy graph, but this is actually very very interesting. And this is Eldorado, and Ken's sitting here, so if you have any specific questions about what he did, you can talk to him.

But this is starting on Saturday. So here's the week before; so here's Saturday; here's Sunday; there's a call. What did they do? They shut everything off, right? And that's about 2 megawatts, from noon to 6:00. That's on Monday; they shut everything off from noon to 6:00 on Tuesday. And look what happened on Wednesday. They started running out of water, and they said, we can't do this, we can't shut everything off for six hours.

But they did something that's really interesting, which you'll see, is if you look over here, they had to recover on Wednesday. But on Thursday what they said is we can't shut everything off for six hours, but we can shut about half of it off for three hours, and shut all of it off for three hours.

So from noon to 3:00 we're going to drop about half of our load; and this is two accounts. This is the freshwater pump, their raw water pump out of Folsom and the treatment plant down in Eldorado Hills. And then you'll see the next day on Friday, they did exactly the same thing.

And then what you'll see, the next week, is on Monday and Tuesday is exactly the same thing happened. This is Saturday; this is Sunday. Look at Monday. They drop about half of their load for three hours; all of it for three hours. And then on Tuesday, about half for three and half for three.

And remember what we talked about is originally the system was set up sort of so they could drop six hours with the idea that they would do it and they would recover a little bit the next day and a little bit the next day.

They tried it for two full days and they said, we can't recover. Let's refill everything. But then there's something that we can do. So, we'll drop half of it and then we'll drop all of it the rest of the time.

Okay, continuous heat days cause problems. But you can see the water agencies can respond if they're as creative as Eldorado is, and still be able to contribute.

No necessary onpeak, no necessary demand response fatigue, depending upon what their alternative is, if it's using pumping or not. Demand response fatigue from if there are multiple heat days.

But this is one point that I wanted to bring. Remember, these are systems that are built with water agencies; water agencies that built their storage to maximize the efficiency of their water system, not for onpeak storage.

If we had storage that was just for onpeak electrical use, we wouldn't necessarily have the fatigue response.

And so here's the summary. There's about 1000 megawatts, conservatively, that we could get within the water -- this is technologies we know; we know how they operate. This is storage or alternative pumping facilities, with a couple things.

Allow the water agencies to aggregate all their accounts for demand response. Because what you'll see is even in the Eldorado Hills project, I'm only showing you two, but there's probably 40 separate accounts that are down there that aren't included in this, because they're either too small or for some other reason.

The other thing to remember is all that water when you run water out of storage, all that is water sliding downhill, not generating any electricity. It's really easy to put a hydrogenerator on there. We can't do that right now. And one of the things we're looking at with Eldorado is we're looking at doing that because our load is not where the generation is. And so, the generation is not cost effective to sell into the wholesale market.

Incentives to shift out of the onpeak permanently. One of the things that -- knows, we have demand response and we have conservation. But right now there's this huge hole which the water agencies are perfectly capable of doing, is shifting their electrical demand out of the onpeak period, but there are no incentives for that.

You either fall into demand response, which you can come on when we call you; or you fall in conservation in which you're all the time. And so we will be filing proposals with the Public Utilities Commission for programs to do just this, to provide incentives for water agencies or for whoever to permanently shift some of their built storage or whatever they want to do, but permanently shift some of their electrical load out of the onpeak period.

And then the last thing, which is being

funded here, which is the project for time-of-use water meters, the demonstration. There's a -- we have some, a PIER proposal before this Commission that we're working through the process, to put in time-of-use water meters for the water customers.

And if we can convince the water customers to shift some of their water use out of the onpeak period, that will reduce the amount of electrical demand that we will have in the onpeak period. And basically we'll have demand side management on the customer, water customer, side like we have it on the electric side.

Thank you.

MR. GIBBS: Thank you, Dr. House. While we're on water issues, I think we will have Ken Kremesec say a few words about their experience.

MR. KREMESEC: Our experience was very positive. We had a lot of creative operators running those facilities, trying to come up with ways that we can maximize our electric use without jeopardizing the water system, as Dr. House was explaining.

PG&E's been very cooperative with us in allowing us to reduce the amount of electricity that we have to use. I'd probably be better to field questions than just to speak.

ASSOCIATE MEMBER GEESMAN: I guess I would observe, in no small part, due to Lon's contribution last year, this Commission spent a fair amount of time exploring a better nexus between water and energy concerns.

I'm pleased to say that Commissioner Bohn at the Public Utilities Commission has taken up this issue for further pursuit.

This is a scenario that I think is extremely important to the state's overall interests. And I think both from the water agency standpoint and from the utilities' perspective, time invested here will pay off big in the future.

PRESIDING MEMBER BYRON: Mr. Kremesec, so these conclusions that were provided in the presentation also apply to your water district for, I should say your irrigation district, as well, correct?

MR. KREMESEC: That is correct.

PRESIDING MEMBER BYRON: That's a real eye-opener for me; 1000 megawatts you've taken out of the electrical system during the peak period; that's very good.

MR. KREMESEC: And what Dr. House was

explaining about how our water system works, which is we take the water high in the Sierras for about two-thirds of our system, and flow it down through gravity. And there's a lot of potential there for energy production.

DR. HOUSE: And if I could just interject here, what we're talking about, what you saw in your presentation was the very tail-end of Eldorado, which is Folsom Lake and Eldorado Hills. That's two accounts.

But you've got, I don't know how many, probably hundreds of accounts up the hill; you've got all this water that's flowing down through their system. No hydro facilities in them, no pump storage or response like that. And so there's tremendous opportunity within the water community.

But there's a lot of economic disincentives to optimizing. For each one of those storage facilities, and I've said this before, every time you drive by and you see one of those brown, big brown storage tanks sitting on the top of the hill. That's a big hydro facility. Because we pump the water up to it at night, and it runs down the hill in the daytime.

You can put a reversible pump turbine in, but we don't do that because it's generating electricity not where our load is and we can't -- it's so small we really can't sell it into the open market and make it. It's not cost effective.

So there's just tremendous potential within this industry for efficiency improvements.

MR. ST. MARIE: I would ask are larger tanks more expensive? Right now tanks are built to the size that's required to serve the water system. And there's fatigue, you can't not pump into the tank or you can't avoid using the power for more -- when you're using power for more than a day. What does it take to build larger tanks?

DR. HOUSE: All it takes is an economic incentive because almost every water agency has additional space for storage. They just haven't built it because what they're trying to do is they're trying to optimize their treatment facility. Because the treatment facilities run around the clock.

And so when your consumed use demand is low, you have to have -- you need someplace to stick this water. So you stick it in storage.

And also it allows us to get through the morning peak because the water agency's water demand peaks at 8:00 in the morning. And then it peaks again about 6:30 at night.

But there are -- almost all water agencies have additional storage. And I'll let Ken talk about his. One of the things that we would really like to do is put a bunch of additional storage facilities in Eldorado. And we could pull probably another 10, 12 megawatts off the peak if we could do that.

But the problem is that these are expensive facilities to build. And if you have to recover the investment through, simply through time-of-use rates, you can't do it very well. Plus the variations in time-of-use rates over the years, and you're looking at it right now, which is the reduction between the onpeak period and offpeak demand charges, water agencies just aren't going to do it.

They say we're not going to spend $14 million to shift water out of the -- to shift our electric load out of the onpeak, and base that entire investment on recovering in just regular time-of-use tariffs. Because it's not going to happen.

But they all have them, because they bought land for growth or for changes in the way that -- changes in treatment or things. So almost every water agency has space for storage. They just haven't built it yet.

MR. ST. MARIE: So you're suggesting the time-of-use differentials aren't large enough?

DR. HOUSE: Yes. To make water storage for payback based upon the electric price differential, they won't pay for themselves.

MR. KREMESEC: We've also installed a solar panel array at our Eldorado Hills wastewater treatment facility. And I believe it's about almost a megawatt, 750, I believe. And along with all those locations for additional water storage, there's also additional locations for solar energy production throughout the district.

MR. ST. MARIE: And most of the water agencies have access to tax exempt financing which would drive down the cost of capital. The state seems to have made a bargain with the future in terms of bringing on more intermittency indoor generation system, which creates an obvious need for storage.

The symbiosis here, for better or for

worse, it's probably going to take us many years to clear out the institutional cobwebs that impede progress, but I really do think that both on the part of the electric utility industry and the part of the water agencies, there ought to be some meeting of the minds where you could each create a benefit and value to yourselves and to the other parties, as well.

And I know Commissioner Bohn is committed to trying to work that through. We've used somewhat controversial language like aggregating accounts. I heard you mention that, Lon. We've also suggested net metering as a concept. And wheeling within a water agency to better tap into some of this latent potential.

On the efficiency side, we determined last year that making use of the urban water conservation coalitions' best practices, the eight that they had quantified impacts for, scaling those up to a statewide application would deliver energy savings of about 90 percent, the level that the electric utility efficiency programs currently achieve; and 58 percent of the cost of those programs. Which would suggest the electric utility conservation programs could be roughly doubled in size with a substantial margin of cost effectiveness. Big opportunities.

MR. GIBBS: Great. Well, thank you very much for that. I think we can move on to another customer; Earl Bouse is here, another type of customer, in this case the cement industry.

MR. BOUSE: Thank you. And I don't have the fancy presentation, but we do have handouts that you can get on the counter as you came in, that has a longer description.

The short description is we're non-tax-exempt. I just thought I'd put that out.

(Laughter.)

MR. BOUSE: And, you know, my primary association has been with Hanson Permanente Cement. And on July 24th, as an interruptible customer of PG&E, the entire cement plant was shut down and 30 megawatts were returned to the grid.

The next day, on a voluntary basis, the plant shut its finish mills down, but not the kiln, and returned another 16 megawatts.

But in my recent past I've also been chair of CLECA, which is the California Large Energy Consumers Association. And CLECA is made up of Portland Cement producers. We make the powder that you add the sand and gravel and water to get concrete. Steel producers, air products, specialty minerals and beer. The beer, of course, has got to be cold. No.

The heavy industry realized, you know, -- well, in the '80s when we first began to look closely at the interruptible system. And for our kinds of industry, cement and steel and air products, I'm more familiar with cement, it's a big deal to just shut down with a half-hour notice.

We are manufacturing a product that we mine from limestone and we take this limestone and elevate its temperature to about 2700 degrees. Enough so that the limestone, itself, is melting.

So those particular plants, you know, cost between $250- and $350-million. And when that process is dropped, you know, in this short notice, it means a lot of challenges in terms of returning the plant to production and to making sure that the huge amount of steel that's there is properly taken care of in terms of warping.

When CLECA is in, all the customers together that are in the PG&E and Southern California Edison territories, on the 24th, to my knowledge, we haven't polled everybody, was probably pretty close to 400 megawatts that were returned at that time.

And then the following day there was probably more that was returned on a voluntary basis.

So this has not only been a very very critical part of how each one of the CLECA members operates and how they have to be able to respond, but it's also important economically.

When we first were involved in this in the early '80s, our power costs were about 4 cents a kilowatt hour. And to allow that capacity to be available to the grid, the utilities provided us a one penny return for the 4 cents approximately.

Today, that one cent still holds, but energy is not at 4 cents, as we all know. You know, our CLECA members are paying anywhere from 8, 10 to 11 cents. So it's a risk/reward situation that, you know, for that amount of energy to be returned that quickly, each operator has to look at his annual obligation and what he's being rewarded to do that for.

Thank you.

PRESIDING MEMBER BYRON: Mr. Bouse, it's

great to have you here today. Thanks for coming. Is there any -- does the 400 megawatts represent about all of the interruptible load in the two service territories, do you know?

MR. BOUSE: You know, I don't.

PRESIDING MEMBER BYRON: Okay.

MR. BOUSE: I don't.

PRESIDING MEMBER BYRON: Go ahead, Bob, do you know?

MR. KINERT: PG&E has about 325 megawatts of interruptible load on its system. I know Edison has more than that, but some of that has to do with their direct load control cycling program. I'm not sure what their I6 is.

PRESIDING MEMBER BYRON: So about 800 megawatts of interruptible of Southern California Edison. So my question, Mr. Bouse, would be more in terms of having represented CLECA and representing a large company that uses a lot of energy, there's economic loss here. Do you have to weigh that against the benefit of this reduced rate? You're kind of implying that you might, or others might consider getting off the interruptible rate?=.

MR. BOUSE: When we experienced this in

2001, where we really were in a situation where we were hit just day after day, we would be interrupted, and then we would try, and again we've got a piece of equipment that's 250 feet long, and hen it's got a tower that's 270 feet high, and we're trying to heat that back up to get our cooking going again, we would come back on and then we'd get interrupted.

So, you know, in that particular case day after day we kept getting interrupted. And then at the same time the gas prices, we warm on gas. And the gas prices, gas was almost not available.

So for that particular period, and that's an unusual event, you know, the cement plant and many of the other cement plants and CLECA members just simply gave up, shut down for the month. Now, that's a huge economic loss. But we simply couldn't come back into operation.

So, since that time some improvements have been made. It's a great program; and as long as it's not abused and the users, the folks that are being interrupted can come back and recover for 25 or 30 days at a time, you know, it does work.

As you go along, too, you know, the economic reward has to be there. And the stronger the economic reward, then the stronger the commitment, you know, long term. Once we're committed, we're committed for, you know, that annual period, and we're reliable during that time. And CLECA members have been reliable.

PRESIDING MEMBER BYRON: So one interruption this year, not enough to cause you or others to get off?

MR. BOUSE: No, and I think in hearing everybody else here, not only was it clearly understood that this was very unusual, and I think that's why on a voluntary basis, you know, the CLECA members looked to see what they could do; and literally watching the ISO load online to see when best to pull off. If they can pull equipment such as mills that are a bit more voluntary, and have a bit more flexibility.

ASSOCIATE MEMBER GEESMAN: How do you feel about us treating you as a resource in the state's supply/demand balance tables, we've taken to counting the interruptibles as a resource, meaning that when we project whether our expected reserve levels will be adequate in the coming summer, you're identified the same as the generation.

MR. BOUSE: And I think that's exactly the way we should be viewed because again, and I can speak to, you know, when I was running a cement plant in southern California when interruptible first came in, our company then was run out of Dallas, Texas.

I went back to Dallas and said, you know, this is going to be a program that's going to be very important, you know, to improve the cost of manufacturing cement in California, all I have to do is completely shut the plant down. And I did not get approval. I mean they couldn't believe that we'd even consider that. And, you know, with a lot of negotiation, a little risk-taking on my own, you know, we were able to get it through.

But we had to provide backup equipment to make sure that we could turn the kiln; and we also had to have generation available onsite, and it's not that much, so that we could load our customer trucks.

So, you know, it's not taken lightly, and the commitment is there. There were problems in the past in southern California where people did sign up for interruptible that simply had no business being on the interruptible program.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. GIBBS: Yes, thank you, again. One more member of the panel here is a customer. I'd like to recognize Andy Greene here. We're fortunate to have him here from Contra Costa County.

MR. GREEN: Thanks for having me. As the energy manager for Contra Costa County, I'm essentially overseeing about 5 million square feet of facilities ranging from juvenile halls to courts to hospital and medical facilities and office buildings, and detention facilities.

We participate in two different demand response programs. The critical peak pricing program, we have three buildings on that. And currently we have one building on the demand bidding program, soon to have about 18 more.

We primarily do this to look at ways to reduce our energy costs, and also to play a civic role in assisting the grid when it needs to be -- when that needs to happen.

The way we do it is we have an

integrated building management system that operates and controls our HVAC systems in the buildings. We are looking at adding lighting controls and some cost-efficient way to do that, we will end up doing that, as well. But currently we only control the HVAC systems.

We've been a participant in a CPP test for the past two years with the Lawrence Berkeley National Lab and PG&E. And we've been testing various scenarios on what works best with the kinds of systems we have.

And we narrowed it down to basically adjusting setpoints on our thermostats. Our controls go down to the thermostat control level. And we end up adjusting the thermostat two degrees at two different times during a six-hour event.

And if you're familiar with the critical peak pricing program, there's two periods; a moderate peak priced period from noon to 3:00, and a high peak priced period from 3:00 to 6:00. And so we make that adjustment concurrent with those time periods.

So the County has established 76 degrees as its global, across-the-board cooling setpoint. So we go from 76 to 78 degrees; and then from 78 to 80. And that is how we do that globally with all these buildings.

Now, the buildings that participated in the event during the heat storm was a detention facility -- the three buildings on the critical peak pricing program was a detention facility and two office buildings. And the one in the demand bidding program was our regional medical center.

So, during this -- as we've been saying all day, it was a very unusual event. Having participated in this for the past two years, we typically will have one or two days of demand calls, or event calls, and then we're done for a period of time.

What for us really started it in June, we had a series of demand event calls. And then starting in mid July this heat storm happened.

Overall our results were good. We're not like a water utility or a cement plant, we don't just turn off things. We adjust the thermostat. So what happens, I have some load shapes that I could make available to you; I didn't have time to print them out in slides.

But typically what you'll find is at noon our demands start dropping as the temperature setpoint drops. And then they start ramping back up after a certain amount of time when the building equalizes with the ambient temperature. And then again at 3:00 that same thing happens.

So, our buildings typically will have two different dips in them during the course of the day; and that accounts for across-the-board kilowatt hour savings and demand reduction.

What occurred over the heat storm was persistent heat, and again, overnight temperatures that were quite warm. Two sets of buildings responded differently. The 24-hour facilities, and this would be the detention facility, the jail, and the regional medical center, actually responded fairly well all the way through the course of the demand events.

Now, these demand events, let me recap that a little bit, they essentially were day after day during this time. And I think with one or two gaps. So the 24-hour facilities, because they were being climate controlled 24 hours a day, responded fairly well, though over time the degree to which we had an effect diminished. And these are fairly heavy concrete buildings, both of them. So they had a certain amount of thermal mass that ultimately caught up with the ambient temperature and I would say that the responses diminished over time if you look at the load shapes.

For the office buildings it was a lot more difficult. These buildings are occupied from 7:00 to about 6:00. The building systems are shut down at 6:00, right when the event ends. The building never really has a chance to cool off overnight. In fact, for the office buildings on that Monday, the 24th, so we had a very hot weekend, no climate control in the buildings all weekend, maybe not the smartest thing to do. But our peak was about 500 kW in that building, and it started at 5:30, 6:00 in the morning. And pretty much maintained that whole day, with some slight dips on our response.

Now, in terms of quantifying this a little bit, we were, at peak times of response, were able to reduce about, for these four buildings, 500 kilowatts. And, again, that varies over time. Just as an aside, two of these buildings have PV systems on their roofs.

What else do I want to say about that? Anyway, there was fatigue over time. There was two types of fatigue. We got more occupant complaints over time because the temperatures became less comfortable, at least in the office buildings, over time during the day-in and day-out situation.

And in terms of operator fatigue, and that was primarily myself, during the demand bid process you're notified of pricing; and then you go to a website and submit your bids on an hour-by-hour basis.

Now, what I was seeing was, I guess over time and depending on -- and we can go into these baseline load shapes, but we were not getting a really high value out of the demand response. And so there was some fatigue in going through this process and really not, after awhile noticing that we were not really getting a great reward for doing it.

And then on the critical peak pricing program, because of the unusual event, you know, it's my opinion that we'll actually be hurt over the course of the summer period on this program. Typically I think it's designed to be somewhat revenue-neutral.

For one of our facilities that typically has a bill of about $20,000 in electricity costs, we had about a $5000 hit on just the CPP rate.

And I'll take any questions you want.

ASSOCIATE MEMBER GEESMAN: Did you say that you're expanding participation to include 18 buildings?

MR. GREEN: Yes. Now, what we're doing is those are all going to go into the demand bid program. Again, this was all initiated quite awhile ago, before we started seeing these results.

And it's a learning process all the way through. I mean we're examining some precooling strategies. We're looking at various ways to -- actually, another point is we do stage our return coming out of the events. So each thermostat setting has a delay return on it. So the whole building isn't snapping back at once.

But, so we're learning to utilize the system more effectively; and to somehow use the systems and the weather to our advantage. And all of this is part of our program to just become a more flexible energy position for the County, as a user of energy.

ASSOCIATE MEMBER GEESMAN: Are all of the occupants County employees?

MR. GREEN: Yes.

ASSOCIATE MEMBER GEESMAN: Have any --

MR. GREEN: With the exception of the jail.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: Any push-back from the employees directed at either the CAO or the Board?

MR. GREEN: Yeah, it's interesting. We had quite a debate about this, because initially the past couple years we did this as a blind test. The occupants had no idea that we were doing a demand event. Because we wanted to see -- we didn't want the knowledge of knowing it was happening to affect whether they were comfortable or not.

You might be able to appreciate this.

(Laughter.)

MR. GREEN: So employing my own, you know, psychological test on them, I suppose. And then there was a lot of push-back from -- the County, as you know, has a variety of departments, a big diversity in the type of staff that it houses in these facilities.

And there was a lot of push-back that

the managers of these departments didn't want their employees to know. Because of maybe complaints, the union would complain, various.

Because I really think that, well, I was trying to argue for the fact that the occupants should know to be able to assist us in this; turning off printers that aren't necessary, copiers that aren't necessary, computers that are not necessary, lights that are not necessary. But this is how we're doing it for right now.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER BYRON: Mr. Green, --

MR. GREEN: Yes.

PRESIDING MEMBER BYRON: -- it's also very good to see you here today.

MR. GREEN: Thank you very much. It's good to be here.

PRESIDING MEMBER BYRON: You said something a little bit earlier about critical peak pricing program, and maybe I missed it, but -- did you indicate you were losing money on that?

MR. GREEN: Well, it's hard to know because, you know, we're still within the period of assessing it. Certainly for July we lost money. Now, do we make it up over cooler weather without having -- now, the CBP only has 12 events they're allowed throughout the season, 11 of them have already been called.

So, we're kind of free and clear, so maybe we'll make it up over time; it's hard to know. But that was an eye-opening hit when I saw that bill. So, I'm looking at -- because these prices are what, three and five times the normal kilowatt hour rate at that time period. So, it's significant. And we have no choice, the people that occupy the space. We have to keep them comfortable to a certain degree.

PRESIDING MEMBER BYRON: And if, indeed, it proves not to be revenue neutral for you for the rest of the year, which I imagine you'll take a look at, --

MR. GREEN: Right, exactly --

PRESIDING MEMBER BYRON: -- will that affect your decision to continue?

MR. GREEN: Well, it depends whether we have a choice or not.

PRESIDING MEMBER BYRON: Right.

MR. GREEN: That would affect it. But, kind of the intricacy of this is that, and I brought this to Bob's attention awhile back, but in the demand bidding program the amount that you get qualified that you save is measured against a rolling baseline of the last ten working days.

PRESIDING MEMBER BYRON: Right.

MR. GREEN: And they take the highest three days of that time period that haven't already had a demand been called on them. So, if you look at our typical weather pattern, and I'm not a climatologist by any stretch of the imagination, typically you would then be, during a hot period with a demand event, be compared to a relatively cool period previously. Because typically we have cool periods with these kind of spikes in heat, and then cool periods with another spike in heat.

So, I guess I don't agree with that methodology. And I think it affects what the perceived or the actual value in that program is to customers like myself and the County.

PRESIDING MEMBER BYRON: So would you agree that it might be worthwhile to, you know, talk to customers like yourself that are participating in that program and get a sense of how effective it was?

MR. GREEN: Oh, absolutely.

PRESIDING MEMBER BYRON: Maybe likewise in the interruptible programs, as well, based upon Mr. Bouse's testimony -- not testimony, presentation.

MR. GREEN: He didn't swear in, did he?

PRESIDING MEMBER BYRON: No.

(Laughter.)

PRESIDING MEMBER BYRON: Okay, good.

MR. GREEN: Okay.

MR. GIBBS: Great. Well, thank you. We do have the opportunity to hear from Bob Kinert from PG&E today and talk about their experience with their programs during the event.

MR. KINERT: Okay, well, I'm going to talk a little bit about customer outreach that we've done at PG&E around the heat storm, as well as some of the customer response.

You know, this, obviously from what we've heard all day long, has been -- this was a really huge event for the entire state. And things were just really really different than what we normally experience during the summer.

I beg your pardon, I have to go back here. There we go.

We made almost 800,000 calls in the

midst of the outages to customers who were, in the last six days, -- the calls were handled in the last six days of the heat wave. That's a tremendous volume, if you think about, you know, the number of calls that our contact centers would normally handle.

So, just in terms of everything that's going on, volumes for every function within the utility related to customers were up tremendously.

In the midst of the outages when we had a lot of customers out, you've heard the numbers already from Kevin, we made over 125,000 automated outbound calls to customers where crews were replacing their overloaded equipment. These were proactive calls that were designed to let them know of some short-term duration outages that we were putting in place to get their equipment back online and get them back up into service.

We also, in the contact centers, put in specialized call routing which enabled customers who were being affected by outages to come to the front of the line, the front of the queue for the contact center so that they weren't pushed off to the IVRU or to, you know, a long waiting queue, so that we could get them to a representative as quickly as possible.

We realized, you know, very early on in the heat storm that, you know, we could not do business as usual in the midst of this event. So we were constantly looking for ways to increase the level of customer service that we were providing to customers, and particularly those affected by the outages.

Our customer service representatives also made outbound calls to customers. We had a very small percentage, I think it was one-tenth of 1 percent of our customers were on circuits that were out, and due to equipment issues that took awhile to solve, had extended outages. And in some cases, you know, were out for 72 hours.

We actually called every single customer that we could reach based on information, having phone numbers to call those customers. And we're talking residential customers, not business, here. And offered personal apologies and explanations for their outages. And helped them to obtain claim forms for PG&E if there was a claim form that needed provided for, you know, losses on their end. And then also addressing any other concerns they had.

So we were really trying to go above and beyond the normal routine approach to handling things, given the extraordinary circumstances.

To relieve load, appeals for immediate and prolonged conservation measures were made to customers. And you heard a little bit earlier about some of the voluntary things customers did. Wally, I think you talked about the media; you know, we had some of that discussion that went on, the advertising that was out there in the media.

Actually, Jim Detmers also talked about leveraging the media.

But we also made personal and automated phone calls to thousands of business customers. We had a way to automatically dial out through CONA connect, a system that we use which allows us to do a blast call-out with automated messages to customers.

And then our account managers that manage the relationships with larger customers where you have the opportunity to drop larger blocks of load, a more efficient way to get load off the system, called all their customers.

This is a long-standing practice of the utilities. And in PG&E we've got what we call the over-300 kW list, which is every customer over 300 kW is on that list. Every account manager across our system, 250 people, on the phones calling their customers, asking for voluntary reductions.

We also leveraged email to send messages to customers to continue to reinforce the messages for the need to conserve.

And we know thousands of businesses responded and some in some pretty extraordinary ways. We already heard about Hanson Cement, and the 16 megawatts here today is the voluntary portion of their reduction that had nothing to do with getting paid for dropping their entire load of 30 megawatts in conjunction with the nonfirm program.

This was simply based on a call from PG&E that said, we need your help; can you do something to help us drop the load, you know, we really need it off the system. And they did.

BART, the Bay Area Rapid Transit system, saved about 5 to 7 megawatts simply by slowing down their trains. This was a really creative move. They were willing to, you know, stretch out their schedules a little bit and bring the speed of the trains down. That helped a lot.

The Airport in San Francisco saved 3 to 5 megawatts. They shut down their moving sidewalks; they adjusted lighting. And then made continuing appeals within their facility to save energy.

You know, the point is these are just three short examples. We know EID has been doing some wonderful things. Humboldt has been doing some wonderful things, the irrigation district in Humboldt. Lots and lots and lots of customers. We actually had thousands of customers that did things.

We're estimating that perhaps the voluntary portion of reductions might be as much as 1000 megawatts statewide. And roughly 500 megawatts within PG&E. That's really hard to quantify, but that's an order of magnitude a sense of what we think was going on there.

Also, just to point out that these load reductions also probably help with local outages on residential customers. If the load comes down and, you know, you get some load off the system, you can potentially prevent some things happening elsewhere.

On 7/24, which is the day that a lot of

us have been talking about, at 10:00 the ISO declared a stage one; at 1:00, a stage two; and then at 2:30, the nonfirm and BIPP customers were curtailed. But the customers responded and the load never reached the forecast, as Jim had said.

I just wanted to show you this graph to kind of give you a sense of what that looks like. And if you look at the light blue line at the top, that was the ISO's forecast of where Jim had referenced the load was hit 52,000 megawatts.

And if you look down below at the blue line, that's the actual load that came through. And if you look at the gap between that, that's pretty much the voluntary reduction that was accomplished, simply by appealing to customers to help out with the problem.

So we think this is a pretty incredible accomplishment by our customers. But customers have always done this. The heat storm was unusual; it's a very very different example of the need. But throughout -- I've been with PG&E for 26 years, and I've been working with customers almost that entire time. And I will tell you, I know the customers always step up to the plate. They always help us, when we ask, to the best of their ability.

And it's something that I think, Wally, you were mentioning, the need to acknowledge customers. Well, that was on my mind, too. And one of the things that we did at PG&E we published two-page advertisements, and this is only a list of customers.

We sent out an invitation to all the customers that we had called and asked to give help, the ones that we sent the automated messages to, the ones that we had sent, made personal phone calls to. And we said, gee, we'd really like to just say thank you. If you give us your permission to use your name, we'll run an ad and we'll include your name.

Not everybody, you know, responded back, but about a thousand of them did. And so the ads ran the week of August 6th in the San Francisco, Fresno and Sacramento business journals. And then also in the Silicon Valley and East Bay business times.

And this was the message that we sent to our customers. We said, thank you for partnering with us to conserve energy during the heat wave. And I won't take your time with the more detailed text, but this is what the ad looked like. And you can see -- you can't read this, obviously, but it gives you a graphic sense of the acknowledgement to customers for the efforts that they undertook.

And then finally, as any good company would, PG&E is certainly interested in making sure that we learn, get lessons learned and take those well into account.

So, in terms of preventative actions, we actually did one major thing on the fly, and I think it was touched on this morning when Kevin was talking, we did, as we were going through and replacing overloaded transformers, make decisions in the field, on the fly, where we needed to upgrade transformer sizes. Which prevented us from replacing like with like, and then going and studying it and coming back later and figuring out, gee, maybe we should have put a bigger transformer in.

We were pretty nimble, pretty agile at being able to identify those locations and figure out, you know, what we needed to do.

And then post-event, we're in the process now of going through a really thorough analysis of policy, standards, our systems, procedures, practices, all of that with changes aimed at hardening our system against the impacts of storm-related outages.

One thing in particular we're looking at is what do we do during a winter storm. We tend to treat, you know, the summer, you know, load, heat load and air conditioning loads not as, quote, a storm.

We've all talked about it here today as a heat storm, but routinely throughout the summer we're dealing with capacity and supply issues, as opposed to responding to an emergency.

But I think now it's appropriate to kind of look at this a little bit differently as an industry and say, you know, it's not really any different than the wintertime. And in the wintertime we have a lot -- just a different way of approaching storm season.

So what PG&E is doing is we're looking at what do we do in the wintertime, and how the protocols and the things we do in the wintertime, what is it that we can take away from that that we might want to start to apply to the summer.

And there are, you know, quite a few

other things that we're doing. We're looking at this whole issue you heard from Kevin that we brought in a thousand outside incremental resources to San Jose and East Bay, alone. That was PG&E, that was contractors, that was everybody we could get our hands on to get in there and work those outages to bring about restoration.

So, what do you do when you've got two service centers that are designed to handle a few hundred people, and all of a sudden you've got a thousand people that you've mobilized into that area. So, we're also looking at the logistics. How do we go about those mobilizations in the future. What are some things that we can do to streamline that process and to make those things better.

Materials handling is the same thing. Transformer inventories, it's the same thing. So we're looking at a lot of different aspects to how we would respond to this type of an event in the future.

The one thing that is driving all of this is that we never ever want to experience another event like this in this kind of way. We want to be absolutely, now that we've been through this, prepared in the future so that we can mitigate. You can't eliminate a heat storm, that's an act of nature. But certainly we can be as prepared as possible and examine how we might want to go about addressing this kind of an issue in the future in a way that benefits our customers.

The bottomline is really for all of us, I mean the only reason that I exist in my job and anybody else at PG&E exists in our jobs is because of customers out there. The utility doesn't exist for itself. It exists for its customers.

And so coming up with a better way of handling some of these issues around heat storms or winter storms or whatever it might be, is certainly very worthwhile from that perspective of trying to do a better job for our customers.

Thank you.

MR. GIBBS: Thank you, Bob. Are there any questions? Thank you very much, and appreciate the description of the proactive manner in which you are reaching out to customers. I guess I would just ask, we also have the opportunity here with some representatives from the other utilities, whether they would like to say a few words about their efforts in reaching customers and the voluntary responses in that regards. If there's anyone interested in doing that now, or we can -- okay, if there's interest, later during the other comment period we have after the fourth panel.

So, if there are no other questions from the Commissioners at this point on this panel, thank you so much. Very very helpful and interesting panel on customer response.

What we'll do now is we're going to have our fourth panel, looking at what we can look forward to next, what's coming and what we can learn from the heat storm.

So, -- panel to join us here at the table.

(Pause.)

MR. GIBBS: Okay, thank you very much to our three panelists. We have Sean Gallagher from the Public Utilities Commission; Jim Detmers has agreed to help us yet again here, from California ISO; and Scott Matthews from the Energy Commission.

They're going to say a few words about the discussions today, the information today. And then we'll open it up for comments and discussion. So, we'll start with Sean Gallagher from the PUC.

MR. GALLAGHER: Thank you, and good afternoon, Commissioners. I'm going to start, I thought I'd start this panel with a couple of slides on some of the things that the PUC is doing in response to the heat storm.

We, like you, are still accumulating information and starting to perform some analyses, but we have done a couple of things already to try to prepare us, both for the remainder of this year, and for coming years.

We've taken actions in three areas, energy efficiency, demand response, and generation. On the energy efficiency side, as was mentioned earlier, the Commission did approve three-year program cycles for 2006 through 2008 earlier this year.

We've now asked PG&E and Edison to go out and solicit some additional third-party programs using the approved budgets; the budget approval decision did allow for some fund shifting and for some flexibility in the programs that were chosen.

And in particular, those efforts are

aimed at looking for innovative targeted energy efficiency programs that focus on high-demand areas. So we're specifically looking for energy efficiency that's aimed at peak.

On the demand response side there's three activities that are going on now. One is we're looking for more a/c cycling. Second, we approved some resolutions last week to increase demand response programs for this summer. And then we're also looking to increase demand response activities for next year and beyond.

With respect to air conditioner cycling, President Peevey issued an assigned Commissioner ruling on August 15th. It directs Edison, one of the two things it does, we'll talk about the other in a moment -- it directs Edison to bring more than 300 -- to bring 300 megawatts more a/c cycling online by summer of 2007.

The a/c cycling program is one of the more effective programs that we have, or more cost effective demand response programs that we have. It's also dispatchable, very reliable. It's one of the things the ISO really likes.

We've also asked PG&E and San Diego to report on opportunities that they have to expand their a/c cycling programs. PG&E already had approved a pilot program for next year, and they're at least considering bringing to us a full-fledged a/c cycling program for next year.

For the demand response programs for this summer, I mentioned the Commission, at last week's meeting, approved tweaks in four program areas to try to incent or obtain a little bit better demand response for the remainder of this summer.

As you know, even though we're at the end of August, we can still see some high loads into September and even October during certain times. And I won't go into the details, but we made basically minor changes to several programs to try to draw more participation into those programs.

And then for next summer and beyond, there's been a lot of interest in demand response since the heat storm. We have, as on the energy efficiency side, the Commission earlier this year approved three-year program cycles for demand response programs. As in the energy efficiency programs, there is some flexibility with respect to those programs. There's opportunities for funds to be shifted from one program to another; or as new programs are identified, to move money from one area to another.

And so we've asked all three utilities to come to us with proposals by August 30th, I guess that's tomorrow, with what else they can do; how they can enhance and improve their demand response programs for next summer.

We're going to put this on a very fast track and we expect to issue a decision in the late fall.

And with respect to new generation, President Peevey's August 15th ruling also asked Edison to look into putting in about up to 250 megawatts of new peaking generation in their service territory that would have black-start capability, be dispatchable and support local distribution system.

That 250 megawatts is in addition to Edison's long-term RFO that they are currently in the process of going through. And, in addition, Edison is going to add what we're calling in a shorthand way, an ultra-fast track to their RFO so that suppliers that have the ability to bring generation on as soon as next year will have an opportunity to make those proposals to Edison in the context of the RFO.

ASSOCIATE MEMBER GEESMAN: You seem to have focused a lot of your effort since the heat storm on Edison. Is there a reason for that?

MR. GALLAGHER: Well, I'd say we've focused our efforts particularly in southern California, but not solely in southern California. Going into the last couple of years, the CEC forecast, as well as the ISO forecast shows that conditions are simply tighter in southern California. That is, the supply/demand conditions are simply tighter.

ASSOCIATE MEMBER GEESMAN: Yeah, I mean I think that's why it's so inexplicable to us as to why we seem to have such radically different views as to the needs in the Edison service territory going forward.

In July, before the heat storm, the long-term procurement decision your Commission adopted approved Edison's request, which was based on a 2004 forecast that they had made, 1500 megawatts of new long-term procurement.

Our recommendation to you was something on the order of 6000. As I indicated this morning, that was before, or without reflecting the adjustment upward in our demand forecast that we made since last summer.

Now there's an ACR for 250 megawatts. It seems like we're on different planets.

MR. GALLAGHER: Well, I think you answered your own question, Commissioner Geesman. The decision that was issued in July was based on the 2004 need assessment that was made in that proceeding.

We haven't had the opportunity yet to consider your recommendations in the 2005 IEPR, or the revised forecast. That'll be done later this year. And we expect to make a new need finding based on those new numbers later this year or early next year.

ASSOCIATE MEMBER GEESMAN: Well, you know, we made those recommendations to you last November. And I think that's an alarming lack of urgency attached to any of these problems. it's been 15 months since Pat Wood, George Bush's Texas homebody, characterized our efforts in California since the crisis as a D+ on infrastructure.

What have we done in 15 months to improve that grade? I don't think anything. And now you're suggesting that you'll get around to dealing with our recommendations later this year or early next year. I don't think that's an appropriate response.

MR. GALLAGHER: You're certainly entitled to your opinion.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER BYRON: Sean, if you go back a couple slides, I was really curious to see the different response programs for this summer that the PUC is undertaking. Did I understand you correctly that you're looking for the utilities to provide the input to that?

Let me say it differently. It's unfortunate our customers have left. It might have been good if we had a chance to get a little feedback from them on these. But, can you give me a sense how much you think these might represent in terms of demand reduction?

MR. GALLAGHER: Well, there's two things. Last week, as I said, we made some changes to four of the current demand response programs intended to address the remainder of this summer.

On the top of the slide here, it's

resolution 4009, we think that the change in this program alone could result in as much as 50 megawatts of additional demand response participation. This is the demand reserves partnership program where most of the load in that program is the CDWR pumps.

There are a number of other businesses that are signed up for that program, but they simply haven't been participating in the program because it's been called too often under the current trigger.

So what we did in this resolution last week is we modified the trigger. It will call the program somewhat less often. We hope that will give customers incentive to participate in it. And then actually be there when we need them.

The other thing that we're doing is we've asked the utilities to make demand response proposals to us by August 30th, I guess that's tomorrow, for next summer and beyond. Now we haven't specifically asked the customers or the customer groups to make proposals to us, but they'll certainly have an opportunity to weigh in on utility proposals, to suggest additions, deletions, changes, and let us know their views.

You know, we probably could do more in terms of outreach to the customer groups, and I'll take it as a suggestion from you that we do so.

PRESIDING MEMBER BYRON: Okay, great. Great, thank you.

MR. GALLAGHER: That's really all I had for this part. I'll rejoin the table and be available for questions.

MR. GIBBS: Okay, thank you, Sean. Are there other questions before moving on? Seeing none, Jim Detmers, you're next up to provide your perspective on the discussion so far today.

MR. DETMERS: Okay, I'm just finishing my comments. All right, thank you very much. And it's good --

(Alarm interruption.)

MR. DETMERS: That wasn't me, was it? Again, I want to say thanks for having this workshop. I think it was very good, very very helpful for me to again organize some of our thinking around what did we deal with, what have we learned, what do we need to do next, because that is really critical here. To make sure that we've got, again in my terms of investment, the money in the right locations again.

And we need to know where to put our money; how long to put our money to make sure that it's consistent with our long-term goals, as well as our short-term goals.

And so as I look at what we do in this industry, and as I've worked on it for -- at the ISO for the last nine years, the way I see the organization coming together, the overall industry, and that includes regulators and everyone else, we are probably at the point right now of being the most organized that I've seen in all of those nine years.

And to having dealt with the startup of the markets; dealing with the whole energy crisis, or the financial calamity that occurred back in 2000/2001. And now to get to a point where we can continue this effort, I think we have to continue with the positive trends.

So, I tried to collect my thoughts in going back down through all of what I heard today. I may miss a lot of things, but at least this is a start of what I'm focused on.

And it comes down into three basic categories. The first category, what can we expect to repeat itself, looking forward. What is most likely the trend of what we can expect.

Second one is what should we not expect to be there. What is unlikely to reoccur that might require additional attention, more focus and more efforts than the first part of the investment stream.

And what should we really look at, thirdly, at being expedited. Stuff that we know, we know that's consistent with our long-term vision, and we know that we really need to really get after. And I think some of these points go to Sean's points, as well, that he raised that I think are consistent with where the state's loading order is. I think it's consistent with where we need to go.

The details might not be there on all of these points, but I think it's at least worth focusing on these.

So, again, the trends expecting to be there. We know the load's going to be there. The demand's going to come back, every summer it gets hot. And that that load actually grows at roughly 1000 megawatts a year, just the basic growth.

So even if we were to take out this anomaly, or if any of the weather forecasters want to rule that out, that 1000 megawatt growth is most likely going to be there.

And I don't see it any less. I see the economy continuing to grow. And it's in all of our eyes, all of our minds, of watching what's happening. So we need to be ready to deal with that 1000 megawatts a year. I'm not sure if we have the supply to be able to handle that. And that comes later on here.

I think one of the things that we did learn today, what I'm still very proud to say that I'm still a part of the industry because at one point in time, back after the energy crisis, I said I got to find a new industry. I said, this isn't it. But I can sit here today and say I'm proud to be a part of it now, again. And that's a good thing.

But that comes with hearing all the coordination. Everybody basically working together and coordinating, collaborating and everybody doing that. So I think that can be repeated.

I think the next one is forecasting. I think our forecasting is really there and it needs to continue on its improvements. But I think with a little help, very little help, it'll continue on its track.

I think the operation of the transmission grid and the maintenance on the transmission grid is also there. We've got that pretty well worked out. And it's going to continue.

Lastly, on this front, that I wrote down and then I ran out of time, is that customers will be there in response to help us. And so I didn't hear it as the thank-yous that I should have given to the last crowd that was here, but I need to thank them again because customers were really there.

They are a part of this industry. They are a part of the response of what we need to do. And I think we need to work with them so that we can get this demand side thing right. Not get it so it's right for the utilities, not get it right just for me at the ISO, but get it right for those customers. Because that's what we're doing this all for. And we owe it to them, and we owe it to us, as well.

The second major category is what should we not expect to be there. And these are, in my opinion, again, Jim Detmers, the engineer that works out at the ISO, but I have about 20 years worth of experience doing this. And I think we've got enough experience underneath our belt and with all the input that we received from the different panels, that some of my points here should be recognized.

Imports, with the tight conditions that we just experienced throughout the west, are not going to exceed the levels that we just experienced. We set this system up to be able to get to those imports, as you've heard from Bonneville and you heard from me and you heard from everyone else.

I would not expect them to exceed that 9000 figure again. Some of our forecasts on supply conditions have it still going upwards of 10,000 or 12,000 megawatts of imports. There's other conditions that have to come into play if we are going to expect and do have that contracted, to be able to get it up to that level.

But with the --

ASSOCIATE MEMBER GEESMAN: Would you expect that level to go up if we had a Devers-Palo Verde 2 line?

MR. DETMERS: With that particular condition, yes.

ASSOCIATE MEMBER GEESMAN: Would you expect it to go up if we had a Sunrise Power Link?

MR. DETMERS: Probably. Only because those two examples, Commissioner Geesman, that you just cited -- now, you're going to get my passion going here again. But I would expect that to go up because we know that there is an over-abundance of generation capacity in those areas. What you're going to pay to get that in, that's a different story. But I would expect those lines to be fully loaded once they go into service.

Now, does that mean that other paths are backed off, maybe, if there's nothing secured on those other fronts. And we're only just trading off from one location to another, so some other supplies on other ties may actually go down.

ASSOCIATE MEMBER GEESMAN: What would you see being backed off?

MR. DETMERS: Well, some of the conditions that we were just hearing from Bonneville, for instance. The Northwest was at an optimum hydro condition. It goes down to my last point here, but hydroelectric conditions that we just dealt with were optimum and --

ASSOCIATE MEMBER GEESMAN: Couldn't have been much better, could it?

MR. DETMERS: You can't get much better than the Northwest having everything. And we had a snow pack that's still up there right now. There's still snow caps on top of the mountain.

And so with those hydro conditions, can we expect that to be the case again? When was the last drought in California, the very severe drought conditions? Well, I have to think back to the '70s, back '73 or '70-something, to be able to remember a real drought. There was one in the '80s, but I don't think it was that bad.

Are we ready for that condition to exist. But, again, that will definitely impact. But what we have done is heightened sensitivity of all the other utilities around California that will be wanting to protect their own systems. Can we expect that to come in, the same mistakes to be done again on the outside.

There were mistakes, and then there were plays that were set up by California to make sure that we can bring that in. All of that worked. But I don't expect it to be there again. Yeah, we can tie into some additional resources; if those resources are secured for California, then that's good.

The next point underneath, and I hit the hydro point, next one, what should we not expect to be there. Generator availability. Again, as we heard earlier, the aging fleet is still getting older. You made the point, Commissioner Geesman, about that, what needs to be done for repower.

We need to make some decisions, as California, and decide what to do with that. Gain the efficiencies out of repower. Take generators and basically their efficiency would be double what they would be on the existing facilities. You save on the natural gas side. You increase that efficiency. There is just win, win, win.

So, let me keep going here and what should we look at expediting, because some of this feeds back up into these other areas here.

First thing we really need to focus in on is, as the PUC is working on, as well, is demand response. And I'm a dispatcher and an engineer and an operator at this system. But I am convinced that we have to really understand better what those customers need so that we can figure out how to really start mining, what I would call mining, demand response throughout California. It's the next gold to be found in this field.

I don't think we have it quite right, just solving it the same old utility way of doing things. And I think there's a lot of ways that we really need to explore using some of the examples of the AT&T deregulation of how things happened; of moving demarcation points across the telephone systems.

And if you all recall, we moved the demarcation point on the phone systems, I recall, as a Californian, of all of a sudden now owning the wires coming into your house. What could be done to get the competition in to getting that information into the customers' hands that are coming off of that meter, so that they have it instantly, just across the internet and what-have-you. There's got to be ways of getting that done. We're just not opening that door, yet. So demand response needs to be expedited in all different forms.

Transmission. The transmission system has needs; and there are elements to be gained by increasing transmission capacity, as you indicated, on the southwest power link coming into San Diego on the Sun Path, or on the Palo Verde-Devers, or our Pacific Northwest tie.

All three of those elements, there are things that can be done immediately to increase capacity of all of those transmission systems. We need to get after those projects and expedite, as well as internal projects to California where we need to get those.

New generation, as well as repower, and I'll refer to this as quick-start resources, both demand response and new generation or repower could be in the form of quick-start. Things that can be accomplished very quickly.

In effect, what we were just dealing with was a, to one degree, a forecast error, because we didn't expect it to get that hot for that prolonged, and we were able to perform on the system.

We've had numerous occasions where our forecasts have been off, during from one day to the next. To the degree of having that off 2000 to 3000 megawatts off, and I wind up short all the time. So if we're going to get the investment right of new generation and/or demand response, we need to get both of those into quick-start mode and quick response mode.

And lastly, on what we need to expedite is making sure that we're securing all of the resources necessary to meet '07, and we do that immediately. One of the things that hasn't been finished yet is the resource adequacy proceeding for '07.

I know that that's coming to a close here within the next few weeks, but we have to make sure that they have really secured all the resources necessary through that procurement process. And get to getting that expedited. Because that was one of the greater successes that we had, but we need to repeat that. And we need to fulfill all of it so that it meets our needs for '07, as well.

I think all of those recommendations are what we need to do today, as well as they're consistent with our long-term plans, as well.

So, I'll leave it open for questions. Thank you.

PRESIDING MEMBER BYRON: Well, the ISO did an excellent job. I don't think we should let you have a pass, though here today --

(Laughter.)

MR. DETMERS: I need a vacation; can I have a vacation?

PRESIDING MEMBER BYRON: Jim, really, you know, I'm trying to list things, too. And I think you did an excellent job of going through all the possible lessons learned from this, from the ISO's point of view.

I really don't have a question, I just want to thank you very much for all that you did and that the ISO did keeping us going through the month of July.

MR. DETMERS: You're welcome, thank you.

MR. MATTHEWS: I'm going to follow Jim Detmers' lead and stand up here. I rarely get to; I always sitting over there.

What I want to do is answer the three questions that were on the agenda. What have we learned; what's ahead; and what do we still need to know.

Starting with what did we learn, there's three areas I want to talk about a little bit. One is the system responded surprisingly well, in large measure thanks to Jim Detmers. And I want to echo some of that, Jeff, and give you a little more detail about what he's pulled off.

We've experienced at least the limits of our risk tolerance. And one thing that hasn't been mentioned at all today, I want to talk about just briefly, is that we, as a state, were not prepared for the heat-related deaths that occurred.

I want to remind you about last year, which was a cool summer that we didn't get any major heat events. We had a number of outages caused by things such as one that Jim just mentioned, missing the forecast for the next day or for the morning-of, knowing how hot it was going to get.

There were a number of communication errors resulting when the ISO needed power and called friendly neighborhood utilities and they refused to answer the phone or sell power.

And then there were a number of transmission infrastructure problems where systems failed for one reason or another. The ISO, under Jim's leadership, worked on all of those, and none of those occurred this summer.

We had an unbelievably unlikely event occur this summer. And nevertheless, I think if we had proposed this scenario that occurred to Jim in the fall or the spring he would have told us we would have been in rolling blackouts. A lot of it is because people did tend to pitch in because we needed them to.

When we do our forecast of the summer we do a probability for a series of factors, what's the demand forecast going to be; how much generation's going to be online; how much transmission is going to come through the system.

And we treat those all as independent variables. And what you discover is that when things get really tight, people, in fact, do come through. And that happened here.

Especially, and Jim has been exceedingly gracious to all the rest of us for what the customers have done, what the operators have done, that transmission people have done. But, we saw what happened.

And so, you know, this job of trying to determine how much electricity we need is a portfolio of various kinds of things, generation, transmission, demand response. And like any kind of portfolio, you need to know what your risk tolerance is. And we, on the planning side, because we're not responsible, like Jim is, for having to guarantee that, in fact, the lights will keep on, we tend to be a little more risk-tolerant than he does.

The policymaker, you, and the PUC and the other entities here need to decide where it is that we should balance the amount of resources that we have versus the amount of demand that we get. And so that can be by changes in what the reserve margin is, or changes -- and all these have been suggested -- changes in, you know, whether we go to the one-in-ten forecast rather than the one-in-two forecast, or one-in-15 forecast. Do we build more redundant transmission distribution systems. Do we add more peakers, et cetera. And Sean presented some of the things that the PUC is proposing to do.

But I think the fundamental question still remains, you know, what is the right reserve margin for a lack of a better measure.

The other thing we learned is about the heat-related deaths. And I just want to do this quickly, because I personally got involved when the Governor created an energy emergency task force. Mainly because we, in the energy business, know a lot about weather, as was demonstrated clearly today.

And 138 people died during these events, which is more than died in the Loma Prieta earthquake, more than died in the Oakland fires. I've been fortunate to be involved in helping them connect people like Wally McGuire and Jim Detmers to the emergency services folks so that they're connected when the stages get called, and what the ISO's forecast is, and can connect to the kind of techniques that Wally uses in his systems.

They have drafted a contingency plan under the Office of Emergency Services, state emergency plan, that have done all the kinds of things that we have been doing for some time. Identifying thresholds; figuring out indexes, which in their case is the heat index; getting public information system out; identifying cooling centers, which Sean didn't mention in his presentation, but the utilities put up a number of cooling centers.

The Labor Department has been concerned about this issue for a long time. And they have a whole system out there. There was only one labor-related death during the heat storm, even though people were up on roofs and et cetera, because they had anticipated this. And I think that's going to be a great benefit as we go into the future what OES and Health and Human Services has done.

So, what's ahead. I just want to look at one slide here. This is Tom's slide 7, Tom Gorin's 7. The lavender, is that the color, at the right is what's happened since the ISO got created. And I think Detmers was hired about that second dot down. So ever since Jim's been with us, it's been cool, up until this summer.

But the ISO, in fact, all kidding aside, has experienced relatively benign weather. So I wanted to make that point.

The other point is if you look and try to anticipate, you know, what's going to happen based upon the past, which may or may not be a good indicator of what's going to happen in the future, but it's all we got, you'll see that we don't ever have two back-to-back heat storms. Not that it couldn't happen.

But these things tend to go in cycles. And so you tend to have a series of hot summers followed by a series of cold summers, et cetera.

You heard the information about global climate change. I don't think anybody knows, you know, exactly what's going to happen, other than it's probably going to be more variable.

So, what do we still need to know. And this is my list, some of which repeats what Jim had to say. We have to get more demand side response. On the demand forecasting there are a number of ideas that we need to use here at the Energy Commission, and the other demand forecasters, to improve our forecasting assessment.

The impact of humidity on demand. The studies to continue about how customers are responding to requests, whether there's customer fatigue. The combination of what the health people will be doing, which will be telling people that they need to not turn their air conditioners off, to use fans and other devices, and to adopt measures to make sure that they stay cool enough to live through the experience, what kind of impact that's going to have on the electricity demand.

The relationship between nighttime temperature and the next-day peak. The impact of the buildup of heat over time for multiple days. And the issue about that one is what the recurrence of these events will be.

We need to get more information, and the Energy Commission, of course, is doing a lot of this, about greenhouse gas emissions and what that's going to mean. But also, the impact of renewable portfolio standards, more demand response, the aging power plant issue, Commissioner Geesman, that you raised multiple times. You know, can we reduce transformer failure; the consequences of now having these higher rated transformers on circuits. And then ultimately the big question is, you know, what is the right balance of resources versus need.

And that's my summary.

MR. GIBBS: Great, thank you, Scott. Any questions?

ASSOCIATE MEMBER GEESMAN: I guess I'd ask the panel, in general, and we tend to all worship at the alter of demand response, but we had goals set several years ago that we've consistently under-performed. Is there something wrong with the program design? I mean is this a function of if the dogs don't eat the dogfood at some point you've got to change the formula?

It seems to be a very difficult program for the PUC to adopt and then disseminate among the utilities. Why are we pushing on the same rock all the time?

MR. GALLAGHER: I guess I can address that. There's a very wide variety of demand response programs, possibly too wide. I think there's been some concern articulated that there's simply too many programs, it confuses people.

It's certainly true that the demand response numbers have not reached the levels that were hoped for in 2003 when the original Energy Action Plan was agreed to.

I think there are a couple reasons for that, although I don't pretend to know all the answers for it. I think we anticipated getting large customers on CPP rates by now, and we haven't been able to achieve that.

I say I think some of the programs have simply under-performed; certainly program design is an element to that. And some of the things that we did last week were intended to change those program designs to try to get better participation.

In the end, I think the thing that will be most effective in driving demand response is the AMI programs. In June we approved PG&E's AMI program. They're going to start rolling out meters to their 9- or 10-million customers at the end of this year, the beginning of next year. We'll have to adopt some rate schedules that will allow small customers to take advantage of those advanced meters. And I think that's the most exciting area that I see for demand response and where the biggest potential is.

ASSOCIATE MEMBER GEESMAN: I agree with that. Am I wrong that Edison announced some shift just recently about their attitude toward AMI? Proposed a more aggressive rollout schedule --

MR. GALLAGHER: I think that's the way I read it, is that Edison, which in some respects could be seen as lagging in the AMI program, seems to have found some technology that will enable them to get moving on AMI a little bit more quickly than they had previously anticipated. And that's certainly a positive.

ASSOCIATE MEMBER GEESMAN: I wonder if these things aren't likely to prove extremely disruptive technologies in the sense that knowing the very strong bias most stakeholders in this process bring to litigating the question of cost-shifting. Once I know how much Scott Matthews spends on air conditioning, or rather how much air conditioning he uses, why should I, in a temperate climate, be willing to pay for his air conditioning. Will that cause quite a bit of consternation in our program design process?

MR. GALLAGHER: Well, I think that we've seen in the CPP cases that it's not that easy to get these tariff schedules in place. And I don't think it'll be that easy to get the tariff schedules in place for the residential customers. But I think we will do it.

I also, now that I'm able to breathe a little bit, just want to make a couple points about what we have done in the last 15 months since Pat Wood made his assessment.

And we've taken a lot of steps consistent with the loading order that's been adopted by both of our Commissions in the Energy Action Plan. We've approved a $2 billion energy efficiency program. We've approved the three-year demand response program with hundreds of millions of dollars. We've approved and established the

$2.5 billion solar program. We've designed and established the resource adequacy program.

We have the RPS program that we've continued to implement and approve contracts. I'd note that the RPS procurement is in addition to the long-term procurement need. And we've also, more recently, started to reach out to the generator community and to the investment community in New York to try to address their concerns, and set conditions that promote new investment in California.

I think we're making progress on all those fronts. I don't think we're making as much progress as we had hoped, as fast as we had hoped to. But I think we're certainly moving in the right direction.

We're doing it in a way that's consistent with the loading order, where energy efficiency and demand response are first, but all the above are needed, both new generation, new transmission, as well as the programs.

ASSOCIATE MEMBER GEESMAN: Well, and I think that our need determinations and recommendations to your Commission have always been premised on the loading order being quite faithfully followed, so that when we suggest 9000 megawatts needed in the year 2009, 29,000 in the year 2016, that shouldn't be taken as all generation, but rather the entire mix of resources represented by the loading order.

I guess what's frustrating from our standpoint, Sean, is we sit here with 9000 megawatts of inventory and permits have been issued, but not proceeded to construction for lack of a long-term procurement program. That's completely unprecedented in the state's history. Nine thousand megawatts.

You know, you ask, I think, most school children in California what's the problem with power plants, they say environmental restrictions, you can't get a permit. Well, we've found sites for 9000 megawatts of projects in the state that have not been able to proceed to construction because our procurement process seems to be constipated. There's something wrong with that.

MR. GALLAGHER: I don't disagree that there's something wrong. Let's place this in context. In 1998 when we opened the new market, the utilities were out of the procurement business. And new power plants were going to appear magically by virtue of the market.

Well, in 2003 we decided that we'd better do something else. And the utilities reentered the procurement business. And we've been designing the program under which they'll do that ever since.

A year and a half ago at an EAP meeting I think I said that we thought we had established the conditions for new power plants to get contracts. We had the long-term procurement proceeding whereby the utilities filed their ten-year plans and showed their need over a ten-year period. And we had the -- that was the long-term side of it.

And we have the resource adequacy which set a one-year need that the load-serving entities had to meet, and that was the short-term element to that.

Between those two prongs we thought we had found, or we had set the conditions under which long-term contracts would be signed, and new generation would be built.

Well, we found that that wasn't the case. In fact, we hadn't done enough. And that's what we tried to correct in the July decision, was we tried to move quickly, and for the PUC that proceeding was quickly, to remove the remaining barriers to long-term contracting.

I think now you've seen that we've done that. PG&E has recently filed an application for the approval of 2200 megawatts of new power plants. Edison's out for 1500 megawatts of new power plants.

Now, that may or may not be enough, but it's certainly a step in the right direction. As I say, it's not the last step in that direction.

ASSOCIATE MEMBER GEESMAN: Well, I hope we have a chance to spend a fair amount of time on this at the Energy Action Plan meeting in a couple of weeks, because I think we need to collectively figure out some way to break through this log-jamb.

I've got a stack of joint documents, joint proclamations of the two Commissions, where in some instances Commissioner Peevey and myself have executed, announcing our intentions to resolve this problem. But for the life of me, I never thought that we'd be sitting here in the summer of 2006 with so many of these issues unresolved.

I understand things take time, but, you know, we've had an awful long time since AB-57 passed in 2002, which was supposed to straighten out procurement.

We're probably not going to resolve this today.

MR. GIBBS: Commissioners, did you have other questions?

PRESIDING MEMBER BYRON: No, I don't. Go right ahead, Mike.

MR. GIBBS: Great. Any other comments from the panel here, having had a chance to hear each other make your comments? Any other additions you'd like to make before we move on?

MR. MATTHEWS: I would like to thank the Committee for holding this workshop, because I think we've all learned a lot. I'd especially like to thank Sylvia Bender for facilitating and getting an excellent set of panels. And I'd like to thank you, Mike, for facilitating this.

ASSOCIATE MEMBER GEESMAN: An outstanding set of panelists.

PRESIDING MEMBER BYRON: But I think we have a little public comment period here?

MR. GIBBS: Okay. Well, thank you very

much to the panel. We ar going to open the floor now to public comment. We do have two blue cards in front of me, and then others who are interested in also speaking will be invited.

The first, I'd like to just welcome William Marcus from The Utility Reform Network. And, if you could, just keep your comments relatively brief; appreciate it.

MR. MARCUS: Good afternoon, Commissioners, panel. My name is Bill Marcus; I'm here from JBS Energy, representing The Utility Reform Network, a representative of residential and small business customers of PG&E and Edison.

We were glad you held this workshop and we appreciate the opportunity to provide these brief comments. There are 20 or 30 more copies of the document that was just passed to the panel out in the hall, and we will figure out how to serve it electronically tomorrow.

We believe it is appropriate to remind the CEC that there are some other important options besides demand response and supply resources.

You heard two key points this morning that residential use per customer is rising over time; and that the weather-adjusted forecast of peak load was 2000 megawatts too low.

Both of these points suggest that peak-oriented energy efficiency that works is of key importance. California must look directly at the source of its critical peaking problems, which is residential space cooling load, as well as other residential loads that are coincident with peak hours, such as swimming pools and electric cooking loads.

TURN believes we need to go back to the basics of energy efficiency, fuel choices and demand side resources that do not depend on new meters. We are far more skeptical about AMI than many of the folks at both the PUC and this Commission. We've provided extensive testimony that expresses the concern that participation and savings will be less than everybody here thinks you're going to get from it. We don't want to be disappointed in five years. We need to look at some other measures, as well.

In particular we look at the utilities' energy efficiency programs; they are not improving load factors on the utility systems very much. They are not oriented to air conditioning.

PG&E's air conditioning programs get them 9 percent of peak and 1 percent of energy, and they are the leaders. Edison gets 2 percent of peak and 1 percent of energy. San Diego gets 1 percent of energy and -- 1 percent of peak and less than 1 percent of energy from its air conditioner programs.

The Bush Administration has made your job harder by setting the efficiency ratio at 13 instead of 14. That leaves work for the State of California and its utilities. You need to emphasize efficiency, both in higher EER and SEER programs, and in quality installation with proper refrigerant and duct work. This will save summer energy and reduce peak loads under both normal and abnormal conditions. It doesn't have the fatigue and snap-back issues of short-term pricing and demand response programs. The machines just work better.

Some of this is starting to gear up in California, but it's moving slowly, and we need to get this off the dime and move it more quickly.

As part of this you need to consider replacing certain air conditioners early in the Central Valley and other hot zones in southern

California, particularly among low-income customers facing very large bills. We need to get rid of some of these bad room- and central air conditioners.

Air conditioner cycling is a proven technology. We're glad to hear Sean talking about expanding it in the near term. Gives customers a choice to interrupt in exchange for a price break, without forcing customers to make complex usage decisions on a day-by-day basis based on pricing schemes that they may not fully understand.

As I say, we ought to also look at Comverge, which is providing a more high tech demand response and cycling program in San Diego, as one of the examples for moving forward.

Finally, you ought to think outside the box. One way to think outside the box is gas stoves. Electric stoves do not provide those headline megawatts at 4:00 in the afternoon, but your critical peak period goes until 7:00 p.m. Getting the electric stoves out of there will have a significant effect on reducing the peak in those after-hours which also will have an effect on reducing the residential distribution peak.

In addition, they use probably one-quarter as much energy on critical peak days, and half as much energy even when compared to a combined cycle, as an electric stove. And a gas stove is also a good load for the gas companies, because it is a year-round load.

Finally, it's a no-brainer to require swimming pool pumps to be subject to utility direct load control. Before we build supply resources or spend billions of dollars on metering, we ought to get the low-hanging fruit here.

We ought to be taking immediate steps that at least new, if not existing, residential swimming pools are equipped with load control devices. If a household is rich enough to be able to afford to install and maintain a swimming pool, it is reasonable to require that household to be responsible to keep its pool load out of the critical peak period without requiring the utility to pay for such curtailment.

Direct load control. This is a case where regulation of a discretionary load is clearly preferable to other less intrusive and less certain means of dealing with that load; and it's also better than trying to gain the same savings by using pricing programs that have the collateral damage of forcing the elderly to risk illness by not cooling their homes.

A couple quick other points.

ASSOCIATE MEMBER GEESMAN: Let me interrupt you, Bill. Does somebody have the existing legal authority to regulate those pool pumps?

MR. MARCUS: I would think that under the Title 24 and load management standards you would have the authority to regulate them on a going-forward basis by saying if you're going to put one in, it gets a load controller.

Going backwards it may be more -- going back to the existing fleet may be more difficult.

We also think that you ought to look outside the box at a few other things, such as changing the bid processes for transformers, to start reducing transformer losses, particularly the load-related losses that are highest at peak.

Looking at conservation voltage regulation. Edison has identified some options for peak periods back in 2001 that have not been pursued.

Looking at combined heat and power with

producing chilled water. Our medical center in Sacramento produces 25 megawatts of generation and 8 megawatts of reduced air conditioning demand at the summer peak.

ASSOCIATE MEMBER GEESMAN: -- in favor of combined heat and power?

MR. MARCUS: As a general rule, yes.

ASSOCIATE MEMBER GEESMAN: Expanding the program?

MR. MARCUS: I'm not sure about expanding the program, but I think --

ASSOCIATE MEMBER GEESMAN: Do you want to see more combined heat and power?

MR. MARCUS: I think in the -- I think we do want to see more combined heat and power as part of an overall process. We're looking at central station generation, we might as well look at more efficient use of it.

ASSOCIATE MEMBER GEESMAN: I would think certainly in terms of the local capacity requirements that are all the vogue now, that would make a lot of sense from your perspective.

MR. MARCUS: I think that's probably true.

Finally, I'd just lastly comment that we need better measurement and evaluation for energy efficiency. Nothing is worse for the state than a kilowatt hour or a peak kilowatt that's saved on paper but not in reality if a utility's over-estimated energy efficiency savings. The increasing residential loads lead us to this concern.

Thank you very much.

MR. GIBBS: Okay, thank you. Thank you very much. We also have Gary Ackerman, Western Power Trading Forum.

MR. ACKERMAN: Good afternoon; I'm Gary Ackerman, Executive Director of the Western Power Trading Forum. One of the toughest jobs in this kind of hearing, of course, is the Commissioners; they have to stay to the bitter end. The second-most tough job is being the last speaker of the day. So let's commiserate together.

Here are some things that we learned by observing events during the month of July in California. And that has to do with the real-time price that was posted, especially on July 24th.

For those who don't watch this kind of thing, the real-time price, once again during a stage two alert, bounced around between $50 and

$100, well below the western region price cap of $400, and even further below a price that was posted on that day in Alberta, Canada, for $1000 Canadian. Even with the U.S./Canadian exchange rate, it doesn't get down from $1000 to 400 bucks. Trust me on that one.

It's been our frustrating experience, and probably we have to take the blame for that. We are unable to educate our state agencies as to why spot prices and investment in California have anything to do with one another, and they do.

Because when investors are looking to develop or lend to new power plants, or hedge funds are looking to put money into new power plants, and they look at California and they see a price signal like they see, with the ISO, they say, I'm not touching that; that thing is not valid.

One trader from a prominent investment bank said to me and a number of regulators who were in New York together, no one trades the ISO real time. In other organized markets they have real-time prices which we utilize. No one touches the ISO real time price.

What does this mean for investment?

Well, it goes something like this. When investors look to lend, or to, you know, take equity positions, they look at what the worst case scenario could be.

And with proper and valid energy prices, they see a lower bound, which is a positive value. Maybe it's below, and certainly it will be below, the cost of new-built, but it's not zero.

The way it looks to them in California is the bottom value is zero, and the only alternate position is for investors to have long-term PPAs and take as few risks as possible. Because there's no way to lay off the energy risk when you don't have a valid energy market. That's exactly what we see going on in California.

So what do they see next when they look at long-term PPAs? Well, they see a lot of resistance to it; but then they see something else that they observe. And I think this, maybe indirectly, relates to what happened last month.

Because if anybody is familiar with the backstop capacity payment that the ISO is willing to provide under its reliability capacity service tariff, that's a fancy way of saying this is what the ISO can procure at the maximum value of $73 per kilowatt year.

Now, compare this to the number that Al Fore, the CEO of Southern California Edison, advised President Peevey at the Commission last week. He said, we can build the 225 megawatts of new capacity that you've mandated us to build for $250 million.

We have to do a little bit of math here, so I'm not going to lose too many people if I take two steps and use multiplication, but it goes something like this, approximately, at least.

$250 million for 225 megawatts, that's approximately $1100 per kW installed. To convert that to an annualized number you use a carrying capacity charge, or something on the order of approximately 15 percent to capture all elements of cost. So, 15 percent of $1100 is $165 per kW a year. Edison gets to recover $165 per kW a year. As a matter of fact, they said it will be at least that amount.

So that's Edison-speak. And let me translate what that means to you. That means it will be over $165 per kW a year, and now that we all are talking the same language, we can proceed.

$165 per kW a year versus what investors can see if they don't have a long-term contract, and an ISO back-stop contract, or arrangement, at 73. 165 - 73. Now, I'm not going to tell you which number is correct, because either way California's kind of screwed.

Because here's what's going on. If $165 is the correct number, then why would anybody invest only to receive 73, less than half the true cost. And if the --

ASSOCIATE MEMBER GEESMAN: The guy getting 165 doesn't care if it operates or not. He's going to get 165 anyway.

MR. ACKERMAN: That's the utility; that's --

ASSOCIATE MEMBER GEESMAN: The guy getting 73 has got to generate to get --

MR. ACKERMAN: Well, how so?

ASSOCIATE MEMBER GEESMAN: He's got to be operable.

MR. ACKERMAN: He's got to be operable, but doesn't have to operate in order to get the 73. Okay, we agree.

If 73 is the right number, then the question is why slam California consumers on 165. One of those numbers is right; one of those numbers is wrong. But what it says, and speaks in volumes to the investment community, financial institutions and prospective investors, is we don't have a valid market. And they're kind of very scared about putting their money in California unless they get a long-term purchase power agreement with all the safeguards that anybody would require.

That's what we're learning again and again, and we learned it again, again last month. And we maintain the, how shall we say it, the interest in working with the ISO and all the state agencies, to get these markets working in a way that they send correct price signals.

Merchants are an animal of price signals. If you want certain investments in certain places to do certain things, you provide a price signal and merchants respond. No price signal, no response. It's that simple.

And the merchants, financial institutions are eager to respond where they see the price signals. And we just don't see it.

So, it's sort of an unhappy lesson that we've learned on that score. Obviously all the congratulatory messages that you've heard today are true, and we share in them and we're glad for all that.

But we know a couple things for sure, and Jim Detmers sort of, I think, characterized it very well when he said the things we can't expect, certainly we can't expect the net imports to maintain at the level they are as demand increases in states outside of California, and reduces the amount of power that can come into the state. And certainly we can't expect every year to have optimal hydro conditions.

So we see the next three years in California as being some pretty tough years. And when things happen I suppose these kinds of meetings won't be so congenial, but we'll certainly go back to you, John Geesman, and say, yeah, you were right, now what are we going to do.

Thanks for your time.

ASSOCIATE MEMBER GEESMAN: Well, are your guys going to respond to the Edison ultra fast track --

MR. ACKERMAN: I don't know because it hasn't -- nobody has sort of issued something publicly that I can see. And I can't see what the commercial deals are behind the curtain, so I really don't know.

Let me put it this way, though. In representations as whether they can, I keep on getting messages that they can. Especially from what I would call the smaller developers who then, in turn, flip those around to maybe a larger organization once they have some arrangement with the utility in place. That seems to be the way it's working.

MR. GIBBS: Thank you very much.

ASSOCIATE MEMBER GEESMAN: Thank you, Gary.

PRESIDING MEMBER BYRON: Thank you, Gary. Before we close, are there other comments from the attendees here who'd like to come up and say a couple words?

Okay, seeing none, I'd like to throw it back to the Commissioners for any final comments.

PRESIDING MEMBER BYRON: Commissioner Geesman, nothing?

(Laughter.)

PRESIDING MEMBER BYRON: Stephen, nothing?

Well, let me just close then with a few things, Michael. First, Steve, we're really glad that you were here representing Commissioner Bohn. And I saw you taking copious notes, as was I.

We certainly got a lot of excellent input here today. I know I have a long list of possible actions, things that we should be looking at here at the Energy Commission.

In fact, Scott, I'm going to just put upon you for a second, if you would -- because you and I really haven't had a chance to speak about this. We had discussed that we'll be doing some reporting out, and I'd like you to just give me a sense or give the group here a sense of when we might be able to see something out of the Commission. Do you mind speaking to that? I know I'm putting you on the spot.

And, of course, as Commissioner Geesman said earlier, we really have a lot to be thankful for in the quality of the panelists we had, even the speakers that came up at the end were fantastic. So, the speakers, especially.

And then I have one more close. But, Scott, can I ask you, can you say anything about --

MR. MATTHEWS: I'm trying to negotiate here with Sylvia to get an answer to your question. She's going to get stuck with putting together a report. Part of it depends upon how much the Committee wants us to do.

PRESIDING MEMBER BYRON: Okay.

MR. MATTHEWS: So, we can put a compilation together quite fast. We are doing this, as you know, some additional work. We're getting new information from the utilities, et cetera, about, you know, about the details as we try to refine our forecast.

So the more time we get then the longer we have. So, it does come to an expectation. We could also do a sort of two-parter here, where we put together a compilation of the materials and do a summary of the workshop.

And then sometime perhaps in the IEPR process or through the Electricity Committee, do a look at the demand forecasting, et cetera, sort of our work and how that should be reflected, given the things that we've learned today and we're learning from the utilities' submittals to us.

ASSOCIATE MEMBER GEESMAN: I would recommend trying to be as proactive as possible, or forward-looking at the summer of '07, for example, as opposed to spending too much additional work time documenting our experience in the summer of '06.

I'd also try to place a real priority on having our analysis and staff resources be of some benefit at the PUC in the resource adequacy proceeding for the summer of '07 as they make the decisions that I think they've got calendared for October of this year.

So, if it's awhile before we see a written product from the staff that's okay with me.

MR. MATTHEWS: All the material that was presented today is on the web now, Sylvia? It will all be on the web shortly, so that folks who want to take advantage of any of these presentations will be able to get to them quite soon.

PRESIDING MEMBER BYRON: Thank you, Scott. I would just like to close with some recognition for the CEC Staff Members that were involved in pulling this all together in some pretty short order. Tom Gorin, Janet Swails, Ardean Baggs, Lynn Marshall, Dave Ashuckian, Dave Hungerford, Guido Franco, Thom Kelly, and of course, Commissioner Geesman's Advisor, Melissa

Jones and my Advisor, Kevin Kennedy. And last, but not least, Sylvia Bender. Thank you all very much for pulling this together.

Thank you for being here today, and I think that will conclude our workshop. Thank you.

(Whereupon, at 4:27 p.m., the workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of September, 2006.